S. Hrg. 98-262

ANNUAL CHARGES FOR THE USE OF FEDERAL GOVERNMENT DAMS AND OTHER STRUCTURES

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

NINETY-EIGHTH CONGRESS

FIRST SESSION

ON

S. 1132

A BILL TO AMEND THE FEDERAL POWER ACT TO SPECIFY THE ANNUAL CHARGES FOR PROJECTS WITH LICENSES ISSUED BY THE FEDERAL ENERGY REGULATORY COMMISSION FOR THE USE OF FEDERAL DAMS AND OTHER STRUCTURES

JULY 25, 1983

Printed for the use of the
Committee on Energy and Natural Resources

U.S. GOVERNMENT PRINTING OFFICE
24-478 O WASHINGTON : 1983

S311-58

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ANNUAL CHARGES FOR THE USE OF FEDERAL GOVERNMENT DAMS AND OTHER STRUCTURES

MONDAY, JULY 25, 1983

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C.

The committee met, pursuant to notice, at 2:05 p.m., in room SD-366, Dirksen Office Building, Hon. James A. McClure, chairman, presiding.

Present: Senators McClure, Hecht, and Melcher.

Also present: Howard Useem and Russell R. Brown, professional staff members; and Craig Gannett, counsel for the minority.

OPENING STATEMENT OF HON. JAMES A. McCLURE, A U.S. SENATOR FROM THE STATE OF IDAHO

The CHAIRMAN. The committee will come to order.

This hearing before the Senate Committee on Energy and Natural Resources is to take testimony from administration and public witnesses on S. 1132, a bill sponsored by myself and Senators Jackson, Murkowski, Symms, and Wallop.

As all of you know, the bill has the objective of encouraging the development of hydroelectric resources at Federal dams by establishing a cap on the fee which may be charged for the use of the dam by a non-Federal power developer and also by clarifying who has the authority to establish that fee.

I think that we owe it to ourselves as a nation to continue the timely development of our hydroelectric resources and that it is prudent to encourage, even now when there are temporary surpluses of some fossil fuels and electric generating capacity, that is for the development of a resource which will be an energy asset for generations to come. I like to think of the Minidoka powerplant in my home State of Idaho. Built in 1908, the powerplant has provided a reliable source of energy for over 70 years to the households, farms, and industries of southeastern Idaho.

However, in this congressional effort to encourage non-Federal power generation using Federal facilities, it is my strongest intent to preserve and protect the rights and benefits of the water users who are now participants in the projects and also to assure the taxpayer that the Federal Government will receive a reasonable return on investment.

Many of you are from out of town and I would like to give you the maximum amount of time to address the committee. Therefore, I will conclude my remarks at this time and ask that a copy of the bill and the statements of myself and Senator Murkowski which appeared in the Congressional Record when we introduced S. 1132 be inserted in the hearing record at this point, along with a statement from Senator Jackson.

[The material inserted by the chairman follows:]

98TH CONGRESS
1ST SESSION

S. 1132

To amend the Federal Power Act to specify the annual charges for projects with licenses issued by the Federal Energy Regulatory Commission for the use of Federal dams and other structures.

IN THE SENATE OF THE UNITED STATES

APRIL 21 (legislative day, APRIL 18), 1983

Mr. MCCLURE (for himself, Mr. JACKSON, and Mr. MURKOWSKI) introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

---

A BILL

To amend the Federal Power Act to specify the annual charges for projects with licenses issued by the Federal Energy Regulatory Commission for the use of Federal dams and other structures.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That section 10(e) of the Federal Power Act (16 U.S.C. 803(e)) is amended by modifying the last clause of the sentence preceeding the last sentence to read as follows: "but in no case shall a license be issued free of charge for the development and utilization of power created by any Government dam, and the amount of such charge shall include the actual unreimbursed cost to the United States, if any, resulting from the construction, operation, and maintenance of the licensee's project works, in addition to an annual rental charge not to exceed $1 per kilowatt of installed capacity and one-half mill per kilowatt-hour of energy produced, and that the amount charged therefor in any license shall be the only charge assessed by any agency of the United States, and shall be such as determined by the Commission.".

○

[From the Congressional Record, April 21, 1983]

HYDROELECTRIC FACILITIES DEVELOPMENT

Mr. McCLURE. Mr. President, on behalf of myself and the senior Senator from Washington (Mr. Jackson) and the junior Senator from Alaska (Mr. Murkowski) I am introducing legislation to amend section 10 of the Federal Power Act which will go far toward clarifying the seeming uncertainties which surround the development of hydroelectric facilities at Government dams by non-Federal entities.

As my colleagues will recall, joint oversight hearings were held during the 97th Congress by the Subcommittee on Water and Power and the Subcommittee on Energy Regulation of the Senate Committee on Energy and Natural Resources to examine the problems surrounding hydroelectric development and licensing procedures. Among the many problems associated with the development of our hydro resources in general are the specific problems faced by non-Federal developers who seek to utilize Federal dams. Two problems came to light during the course of the hearings. First, on the the part of the developer, is the need for clear guidelines to follow in estimating the annual charges which the Government would levy for the use of a Federal dam for a hydro project, and second, is the need to clarify, in regards to Bureau of Reclamation Dams, whether or not there could be a "double charge" for the use of the structure. This legislation would address both problems—but I would stress, only those two problems.

Section 10(e) of the Federal Power Act of 1920 authorizes the establishment and collection of a reasonable annual charge for the licensing of a hydropower project and states in part that:

"In no case shall a license be issued free of charge for the development and utilization of power created by any government dam and that the amount charged therefor in any license shall be such as determined by the Commission."

At this time there is great confusion in the hydro industry as to what those charges might be, and in turn, what crucial effect that such charges may have on the economic potential of a specific site.

Economic viability is the heart of hydropower development and to the extend that we in the Congress can clear up the uncertainties surrounding the question of the annual charge, we will further the development of this important resource. By establishing a reasonable cap on the charges to be imposed for the use of a Federal dam we will provide a stable target that a would-be developer could use in determining whether or not a proposed project is worthwhile. This stable target is particularly valuable to the small developer who may not be able to afford the many services which would be necessary in order to estimate what the annual charge would be; given the complex system of rate computations possible under existing law.

The would-be developer also faces a second problem in the case of Bureau of Reclamation facilities. Section 9(c) of the Reclamation Project Act of 1939 authorizes the Secretary of the Interior to lease power privileges. This has been interpreted to include the sale of falling water or other contractual arrangement to utilize the power head and storage capabilities at Bureau facilities for power production.

In effect, we have authority vested in two entities to charge for non-Federal power development at Bureau of Reclamation dams; the Federal Energy Regulatory Commission via the licensing process, and the Secretary of the Interior through a "falling water" charge. The bill that I propose establishes that the fee charged in the license shall be the only fee and shall be determined by the Commission. Such a declaration should be most helpful in assisting developers to complete the licensing process.

I have said that this bill will promote hydroelectric development, but there are also some important steps in the development process that this amendment to section 10(e) will not effect. It will not effect licensing procedures, nor the need to comply with applicable environments statutes and requirements. The bill does not exempt any projects from existing procedures or seek to diminish in any way public opportunity to participate in the licensing process. The bill will not relieve developers of returning to the Federal Government an appropriate share of capital, operation, and maintenance costs. In addition, the bill provides for an annual charge of up to $1 per kilowatt of installed capacity and one-half mil per kilowatt hour of energy generated. In effect there would be a fixed charge for capacity, and an additional return to the Federal Government commensurate with generation.

It is a fine and difficult line we are trying to draw in respect to the appropriate Federal charge for the development of a public resource. We must strike a balance between the need to provide revenue to the Treasury while at the same time encouraging responsible development. If charges are set too high, there will be no development and hence no revenues. In turn, if charges are too low, the public would not be getting a fair return on the investment of their tax dollars in Federal facilities.

I am looking forward to working closely with the distinguished ranking member of the committee and the chairman of the Subcommittee on Energy Regulation on this legislation.

Mr. President, I ask unanimous consent that a brief statement summarizing section 10(e) of the Federal Power Act and the proposed amendment be included in the Record at this point.

There being no objection, the material was ordered to be printed in the Record, as follows:

"FACT SHEET ON SECTION 10(e) OF THE FEDERAL POWER ACT

"I. EXISTING LAW

"Section 10(e) requires that a licensee pay reasonable annual charges to be fixed by the Commission for the purpose of: (1) reimbursing the United States for the costs of administration of Part I of the Federal Power Act; (2) recompensing the United States for a licensee's use, occupancy and enjoyment of federal lands or other property; and (3) for the expropriation to the United States of excessive profits until the states make provision for preventing excessive profits or for the expropriation of such excessive profits to themselves, or until a specified amortization period is reached. In fixing the level of these charges, the Commission must seek to avoid increasing the price of power to the consumers, and may adjust such charges from time to time as conditions require.

"When licenses are issued involving the use of government dams or other structures owned by the United States and located within reclamation projects, the annual charge set by the Commission for the use of such structures is subject to the approval of the Secretary of the Interior. When licenses are issued involving tribal lands within Indian reservations, the annual charge set by the Commission for the use of such lands is subject to the approval of the Indian tribe having jurisdiction over such lands. Both the government dam annual charge and the Indian lands annual charge may be readjusted by the Commission, upon notice and opportunity for hearing, twenty years after the project is available for service and at ten year intervals thereafter. Such readjustments are subject to the approval of the Secretary of the Interior and the Indian tribe, respectively.

"Licenses issued to states and municipalities for the development, transmission or distribution of power may be issued without charge to the extent the power produced is sold to the public without profit or is used by the state or municipality for state or municipal purposes. Projects constructed by states or municipalities for the primary purpose of providing or improving navigation may be issued without charge and without any limitation placed upon the use of power produced at such projects. Licenses issued for the development, transmission or distribution of power for domestic, mining or other beneficial purposes in projects with an installed capacity of not more than 2,000 horsepower may also be issued without charge except when such projects are located on tribal lands within Indian reservations. Licenses for the development and utilization of power created by a government dam may not be issued free of charge and the amount assessed shall be determined by the Commission.

"Should a licensee make an overpayment on an annual charge assessed pursuant to this section, the Commission may allow a credit for any such overpayment against any future annual charges.

"II. PROPOSED AMENDMENT

"The proposed amendment to Section 10(e) of the Federal Power Act would set a maximum ceiling on the annual charge to be fixed by the Commission for a licensee's use of a government dam or other structures owned by the United States. This maximum annual charge would be comprised of two parts: 1) any actual unreimbursed costs to the United States resulting from the construction, operation and maintenance of the project works; and 2) an annual rental charge not to exceed $1.00 per Kw of installed capacity and ½ mill per kWh of energy produced. In addition, the proposed amendment would provide that said maximum annual charge, as fixed by the Commission, shall be the only charge assessed by any agency of the United States for a licensee's use of a government dam or other structures owned by the United States. In all other respects, the provisions of Section 10(e) would remain unmodified.

"S. 1132

"*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That section 10(e) of the Federal Power Act (16 U.S.C. 803(e)) is amended by modifying the last clause of the sentence preceding the last clause of the sentence to read as follows: "but in no case shall a license be issued free of charge for the development and utilization of power created by any Government dam, and the amount of such charge shall include the actual unreimbursed cost to the United States, if any, resulting from the construction, operation, and maintenance of the licensee's project works, in addition to an annual rental charge not to exceed $1 per kilowatt of installed capacity and one-half mill per kilowatt-hour of energy produced, and that the amount charged therefor in any license shall be the only charge assessed by any agency of the United States, and shall be such as determined by the Commission."

Mr. MURKOWSKI. Mr. President, I would like to express my strong support for the measure to amend section 10(e) of the Federal Power Act as introduced today by the chairman of the Senate Energy Committee.

It is not necessary for me to once again reiterate my strong support for the development of our Nation's hydroelectric resources. During the last Congress, I took the opportunity to express often my belief that we should encourage the continued development of this energy source. By clarifying the question of what constitutes the falling water charge for the use of Government dams, this legislation will help non-Federal investors make sound decisions as to whether or not to go ahead with the investment necessary to develop a particular site.

The potential for further hydroelectric development at Federal dams is significant. The recent national hydroelectric power resources study by the Corps of Engineers gives a good indication of the magnitude of the resource that this legislation could effect. Of the 516 Federal dams included in the study, 168 already have hydro facilities with an installed capacity of 32,000 megawatts. The capacity potential at the 348 remaining structures and the additional capacity at 55 of the dams where facilities already exist totals 13,500 megawatts. In terms of energy produced, there is a potential for 25 billion kilowatt-hours of electricity annually or the equivalent of over 40 million barrels of oil each year. Certainly an important contribution to our Nation's energy needs.

Traditionally, the hydropower resource has been developed by the agency responsible for the water resource project, usually the Corps of Engineers or the Bureau of Reclamation. Last Congress, during hearings on legislation to authorize the Bureau of Reclamation to construct additional hydroelectric facilities at existing projects, the desirability for non-Federal development at several sites became apparent. Further hearings examined the FERC licensing process and the need for coordination among the Federal agencies involved. A significant step in facilitating non-Federal development at reclamation dams was the signing of a memorandum of understanding between the Bureau of Reclamation and the Federal Energy Regulatory Commission. This memorandum outlines the procedures for coordinating the efforts of the two agencies in licensing non-Federal hydro development at Bureau dams.

Mr. President, I ask unanimous consent that a copy of the memorandum appear in the Record at the conclusion of my remarks.

Although laudible in its intent, the memorandum does not fully address the question of the annual charge to the non-Federal developer for the use of the Government facilities. The bill which I am today cosponsoring fills this need—and not only just for Bureau dams, but all Federal dams.

The long-range benefits which would accrue from this legislation are many. By promoting hydro development, we will provide an energy source whose fuel is free and not subject to foreign embargo. We will promote an energy source, which for the most part is environmentally benign—particularly in those instances where existing dams are used. We will provide jobs in construction and related supply industries. And we will provide additional revenues to the Treasury.

As chairman of the Subcommittee on Energy Regulation, it is my hope to hold hearings on this measure as soon as the legislative and committee schedules permit.

STATEMENT OF HON. HENRY M. JACKSON, A U.S. SENATOR FROM THE STATE OF WASHINGTON

Mr. Chairman, I am pleased that we are having a hearing on S. 1132, a bill that I co-sponsored along with you and Senator Murkowski.

As you know, I have long supported the development of our hydropower resources. Hydropower is clean, renewable, and relatively cheap. In addition, it is a domestic energy resource, immune from the vagaries of international politics. For these reasons, I think that we should take full advantage of the hydropower potential afforded by existing Federal dams.

S. 1132 would go a long way toward promoting hydropower development at existing Federal dams. Without restating the details of the bill, suffice it to say that the bill would provide certainty with respect to the amount of the Federal charge. Such certainty would improve the ability of non-Federal entities to make the financial decisions leading to hydropower development.

Mr. Chairman, I look forward to today's testimony, and hope that the Committee can consider this important measure in the near future.

The CHAIRMAN. We will now hear from the first panel. We have with us Hon. Georgiana Sheldon, Commissioner, Federal Energy Regulatory Commission; Hon. Garrey E. Carruthers, Assistant Secretary for Land and Water Resources, Department of the Interior; and Maj. Gen. John F. Wall, Director of Civil Works, U.S. Army Corps of Engineers.

Ms. Sheldon, would you like to go first. You may now summarize your statement, after which your entire statement will be included in the record.

All statements will be included in the record after they are summarized.

STATEMENT OF HON. GEORGIANA H. SHELDON, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION

Ms. SHELDON. I appreciate this opportunity to appear before you today to discuss S. 1132.

I would also like to note that on March 31 of this year the Commission issued a proposed rule which would establish a generic methodology for determining annual charges for hydro licensees under section 10(e) of the Federal Power Act.

Because the Commission must review the comments which were due on July 15 before making a final decision in this matter, I am not in a position to discuss the merits of that proposed rule in the course of today's testimony. My remarks this afternoon relate exclusively to S. 1132 and they are not intended in any way to address the Commission's pending rulemaking.

I want to commend the sponsors of S. 1132 for their efforts to encourage responsible hydroelectric power development. I believe that the proposed legislation would significantly reduce the complexities and uncertainties which currently confront those seeking to develop the hydro potential of Federal dams and other Government structures.

I share the goals of this legislation and believe that, with certain modifications, it will go a long way toward relieving uncertainty.

I believe that it will not only give certainty to developers, but from the Commission's point of view, it is legally defensible. It is administratively simple to enforce. If the level of charges is not adequate, I would suggest to you, Mr. Chairman, that perhaps the $1 might be $1.50 or it might be $2. It might be something other than $1. The one-half mill might be something other than one-half mill.

I think that a balance should be found between the reimbursement moneys to the Treasury for use of our natural resources and encouragement of development of hydroelectric power.

In other words, what is the breaking point when charges will become prohibitive. Should any projects be exempt from these charges and should the FERC be given authority to defer charges if, in some cases, they are prohibitive?

I think those are some of the questions that we should address today.

I would also like to call your attention to page 8 of my written testimony where I make a suggestion about the existing power of the Secretary of the Interior. I am not recommending this course of action. If you wish to realize the maximum extent of certainty if you are going to change the Federal Power Act, that you might wish to change that portion.

The Secretary always has the right under the *Montana Power Company* case to intervene in any of our cases.

Having said that, sir, I would be happy to answer any questions.

The CHAIRMAN. Thank you, Ms. Sheldon, for your summary of your statement.

Ms. SHELDON. Yes, sir.

[The prepared statement of Ms. Sheldon follows:]

STATEMENT OF
GEORGIANA H. SHELDON, COMMISSIONER
FEDERAL ENERGY REGULATORY COMMISSION

Mr. Chairman and Members of the Committee:

I appreciate this opportunity to appear before you to discuss S. 1132, a bill to specify the annual charges which the Federal Energy Regulatory Commission may impose on hydropower licensees for the use of Federal dams and other structures. At the outset I should state that this testimony represents my own views and not necessarily those of the Commission as a whole.

I should also note that on March 31 of this year the Commission issued a proposed rule which would establish a generic methodology for determining annual charges for hydro licensees under section 10(e) of the Federal Power Act. The proposed rule, if adopted by the Commission, would replace the current case-by-case approach to determining the level of annual charges. The comment period for this rulemaking proposal expired on July 15. Because the Commission must carefully review the comments before making a final decision in this matter, I am not in a position to discuss the merits of the proposed rule in the course of today's testimony. My remarks this afternoon relate exclusively to S. 1132 and are not intended in any way to address the Commission's pending rulemaking.

I want to commend the sponsors of S. 1132 for their efforts to encourage responsible hydroelectric power development. I believe that the proposed legislation would significantly reduce the complexities and uncertainties which currently confront those seeking to develop the hydro potential of Federal dams and other government structures. I share the goals of this legislation and believe that, with certain modifications, it will go a long way toward relieving uncertainty.

As you are undoubtedly aware, the Commission on which I serve is strongly committed to fulfilling its statutory responsibilities with respect to hydro development. We have taken a number of steps in the past several years to streamline our regulatory process in order to reduce red tape for developers while ensuring that environmental and safety concerns are fully accommodated. Our licensing procedures have been revised and simplified. We have also established an exemption program which permits small-scale projects to proceed without the need for compliance with complex, time-consuming licensing requirements.

The legislation now pending before this Committee is designed to address another area of concern experienced by prospective hydro developers at government dams: uncertainty with respect to the economic viability of proposed projects due to unpredictable Federal charges. S. 1132 seeks to resolve that uncertainty in two ways: by setting a maximum ceiling on the level of annual charges that can be imposed by FERC for hydro development at government dams and by providing that such charges shall be the only ones assessed by any agency of the United States for that purpose.

The approach recommended by S. 1132 is a sound one, and I would suggest only a few areas where clarification may assist the Commission in carrying out its purposes.

First is the matter of "unreimbursed cost" referenced in line 1 on page 2 of the bill. The maximum ceiling on annual charges proposed by S. 1132 would involve two components: (1) the actual unreimbursed cost to the United States, if any, resulting from the construction, operation and maintenance of the licensee's project works; and (2) an annual rental charge not to exceed $1 per kilowatt of installed capacity and one-half mill per kilowatt-hour of energy produced.

It is unclear precisely what is intended by the term "unreimbursed cost" in the bill as introduced. For example, without clarification it would be difficult for the Commission to determine whether Congress intended the term to include the cost of facilities that are not involved with power production, such as irrigation canals.

The need for defining "unreimbursed cost" is highlighted by the problems which could arise for the Commission in setting annual charges in those cases where licensees at government dams have entered into separate agreements with the Federal agency which owns the dam, usually the Bureau of Reclamation or the Army Corps of Engineers. Such agreements frequently specify that the licensee will pay for some of the construction, operation and maintenance costs incurred by the Bureau or the Corps.

I assume that such contracts provide for the necessary reimbursement of designated costs to the United States. If this assumption is correct, then I am not sure what legitimate additional "unreimbursed costs" the Commission would be required to recover under the provisions S. 1132.

I also assume that these contracts have their own enforcement mechanisms to cover a variety of situations in which nonperformance could occur. If this assumption is wrong, then the bill may have the effect of requiring the Commission, through its power to assess annual charges, to act as an enforcement agent for the Bureau of Reclamation or the Army Corps of Engineers. This could occur either in the case where a licensee was not meeting its contractual payments or where a given contract did not, for some reason, cover all of the costs of the United States which should be reimbursed. In either case, the Commission might be asked by the Bureau or the Corps to collect some of their costs from the licensee.

I believe that the Commission should not be placed in the awkward position of serving as an unnamed third party to contractual arrangements between private developers and other Federal agencies. This situation could be avoided by providing a clearer definition of "unreimbursed cost."

In addition to providing for the recovery of unreimbursed costs, the bill directs the Commission to collect annual rental charges of up to $1 per kilowatt of installed capacity and one-half mill per kilowatt-hour of energy produced. In the interest of streamlining the Commission's administration of the proposed legislation, the Committee may want to consider establishing a fixed charge, rather than a ceiling, for rental charges associated with capacity and the amount of electricity generated.

Section 10(e) of the Federal Power Act sets several criteria governing the Commission's determination of annual charges for the use of government dams. The principal criteria are that the charge must be reasonable, must recompense the government for the use of its property, and must seek to avoid increasing power costs to consumers. In the City of Vanceburg decision [571 F.2d 630 (D.C. Cir. 1977)], the Commission has further construed section 10(e) to mean that annual charges should also be proportional to the value of the benefit conferred on the licensee. As presently worded, S. 1132 can be interpreted as requiring the Commission to develop a methodology for determining annual charges which meets all of the section 10(e) criteria listed above while, at the same time, yielding charges that do not exceed the specified ceiling. The administrative difficulties in making such a determination could result in delays unintended by the authors of the proposed legislation.

I believe that it would be in the interest of administrative efficiency to modify S. 1132 so that an exact level of rental charges is specified by Congress. The Commission could be given the discretion to defer the payment of such charges in appropriate cases where a showing of financial difficulty could be made by the licensee.

The Committee may find it helpful to review the comparison chart accompanying my testimony. The chart indicates the level of charges currently assessed under a select group of project licenses and compares this amount with the charges which would be imposed if the maximum ceiling proposed by S. 1132 were adopted.

Finally, Mr. Chairman, I suggest one additional modification to S. 1132 which would remove a lingering problem with respect to the jurisdictional overlap between Federal agencies which the bill seeks to remedy.

I endorse the policy embodied in the pending measure that non-Federal licensees should be subject to only one charge for the use of government dams. The bill as drafted properly ensures that the Commission, which already has plenary licensing authority over private hydro development at government dams, will be the only agency to determine the charge for the use of those dams.

If this goal is to be realized to the maximum extent possible, the Committee may want to address the provision of section 10(e) which gives the Secretary of Interior power to approve the Commission's determination of annual charges at reclamation dams. I believe that potential hydro developers would be given an added degree of certainty with respect to annual charges if this portion of section 10(e) were deleted. Of course, I fully recognize the continuing right of the Interior Secretary to intervene in Commission proceedings and to make his recommendations on the appropriate level of annual charges known to the Commission. This right was expressly affirmed by the United States Court of Appeals for the D.C. Circuit in Montana Power Co. v. FPC [459 F.2d 863 (February 17, 1972)]. The elimination of the approval clause in section 10(e) would not, in my judgment, in any way affect the Secretary's rights since he would remain an "interested party" in applicable licensing proceedings.

In closing, Mr. Chairman, I want to reiterate my support for the goals envisioned by S. 1132. I will be happy to provide whatever assistance I can in the course of your further consideration of its provisions.

LICENSED PROJECTS WITH ESTABLISHED ANNUAL CHARGES

Project No.	Licensee/ Dam	State	Year License Application Filed	Capacity MW	Annual Energy GWH	Current Charge	Charge Under S. 1132
539	Kentucky Utilities Lock # 7	KY	1924	2.04	8.2	$ 4,400	$ 6,140
1175	Kanawha Valley Power Co. Marmet	WV	1934	14.4	4.8	32,000	56,800
2056	Northern States Power Co. U.S. Lock & Dam 1	MN	1951	8.0	49.3	3,000	27,650
2211	Pub. Serv. Co. of Indiana Markland	IN	1961	64.8	490	39,950	317,300
2165	Alabama Power Company Bankhead	AL	1957	45.0	160	74,000	125,000
2203	Alabama Power Company Holt	AL	1965	40.0	165	67,200	122,500
2570	Ohio Power Company Racine	OH	1973	40.0	222	50,000	151,000
2614	City of Vanceburg, KY Greenup	OH	1976	70.0	300	227,900	220,000
2245	City of Vanceburg, KY Cannelton	KY	1976	70.2	340	243,700	240,200
13	Niagara Mohawk Power Co. Green Island	NY	1977	6.0	42.0	9,100	27,000
362	Ford Motor Company Twin City	MN	1980	14.4	78.8	95,440	53,800

LICENSED PROJECTS WITH ANNUAL CHARGES STATED ON A NOT-TO-EXCEED BASIS IN ORDERS ISSUED IN 1981 or 1982 AND DEFERRED PENDING COMPLETION OF RM83-13

Project No.	Licensee/ Dam	State	Capacity MW	Annual Energy GWH	Deferred Not to Exceed	Charge Under S. 1132
2739	City of Vanceburg, KY Meldahl	KY	70.3	400	$ 638,000	$270,300
289	Louisville Gas & Electric	KY	80.32	374	2,621,000	267,320
2741	Kings River Const. Dist., CA Pine Flat	CA	165.0	420	1,430,000	375,000
2806	City of Carlyle, IL Carlyle	IL	8.75	22.2	36,000	19,850
2832	Boise Project Board - ID Lucky Peak	ID	75.0	282	564,000	216,000
2848	Idaho Power Company Cascade	ID	12.8	47.3	104,350	36,450
2849	East-Quincy-South, WA Main Canal	WA	18.0	75.9	67,617	55,950
3295	East-Quincy-South, WA Summer Falls	WA	74.0	262	222,750	205,000

Use Charges Under Method Proposed

by Commission in Rulemaking RM83-13-000 Versus Method of S.1132

(Hypothetical utility-owned projects coming on line in 1982.)

State	Project Installed Capacity MW	Average Annual Generation GWh	Annual Capacity Factor	1982 Project Cost $\$x10^{-6}$	Ownership	Estimated Annual Net Benefit \$	NOPR Annual Charge \$/yr.	S.1132 Annual Charge \$/yr.	S.1132 Charge as % of Annual Net Benefit
New Hampshire	4.0	12.3	.35	10.0	Private	-369,000	100	10,150	∞
					Public	98,400	49,200	10,150	10.3
Pennsylvania (central)	14.0	36.8	.30	24.0	Private	-920,000	100	32,400	∞
					Public	36,800	18,400	32,400	88.0
West Virginia	14.0	85.8	.70	16.8	Private	1,029,600	514,800	56,900	5.5
					Public	1,458,600	729,300	56,900	3.9
Ohio	70.0	398.6	.65	49.0	Private	8,769,200	4,384,600	269,300	3.1
					Public	8,566,400	4,783,200	268,300	2.8
New York (Western)	6.0	26.3	.50	6.0	Private	394,500	197,250	19,150	4.8
					Public	499,700	249,850	19,150	3.8
Wisconsin	8.0	45.6	.65	7.2	Private	729,600	364,800	30,800	4.2
					Public	866,400	433,200	30,800	3.6
Wisconsin	1.0	5.7	.65	2.0	Private	-5,700	100	3,850	∞
					Public	62,700	31,350	3,850	6.1
Minnesota	14.0	73.6	.60	11.2	Private	515,200	257,600	50,800	9.9
					Public	809,600	404,800	50,800	6.3
Alabama	40.0	175.2	.50	24.0	Private	3,854,400	1,927,400	127,600	3.3
					Public	4,029,600	2,014,800	127,600	3.2

State	Project Installed Capacity MW	Average Annual Generation GWh	Annual Capacity Factor	1982 Project Cost $\$ \times 10^{-6}$	Ownership	Estimated Annual Net Benefit $	NOPR Annual Charge $/yr.	S.1132 Annual Charge $/yr.	S.1132 Charge as % of Annual Net Benefit
Idaho	40.0	140.2	.40	28.0	Private	1,682,400	841,200	110,100	6.5
					Public	1,962,800	981,400	110,100	5.6
Washington	15.0	65.7	.50	18.0	Private	394,200	197,100	47,850	12.1
					Public	722,700	361,350	47,850	6.6
California (or eastern New York)	20.0	52.6	.30	16.0	Private	841,600	420,800	46,300	5.5
					Public	1,578,000	789,000	46,300	2.9
California (or eastern New York)	2.0	7.0	.40	6.0	Private	-217,000	100	5,500	∞
					Public	63,000	31,500	5,500	8.7

Power values and cost of project power listed correspond to utility developers, either privately-owned or publicly-owned. Cooperatively owned utilities do not command tax-exempt financing but do not pay income taxes. Consequently, cooperative utility power values, project costs and net benefits tend to be between those of the privately-owned and publicly-owned utilities.

Power values for determining a non-utility developer's net benefit would be based on the most likely alternative power source, either self-constructed or utility owned. If the latter, the power values would correspond to the costs of the utility purchasing the power or whose load would be reduced by project operation, not the project owner's financing costs.

Project power costs are always based on the actual construction cost and the developer's estimates of his annual operating, maintenance and tax expenses.

The CHAIRMAN. We will hear from Mr. Carruthers at this time.

STATEMENT OF HON. GARREY E. CARRUTHERS, ASSISTANT SECRETARY FOR LAND AND WATER RESOURCES, DEPARTMENT OF THE INTERIOR

Mr. CARRUTHERS. Thank you, Mr. Chairman. It is the Department of the Interior policy that we always attempt to be as agreeable as possible. We agree that we need to encourage hydroelectric development on Federal dams. We are particularly interested in the development of a number of the Bureau of Reclamation dams that exist in the Western States.

As to your proposal, we have some difficulty with it in that it does not generate, in our view, a reasonable return, nor does it address how developers on Federal projects might be selected in the most simplified fashion.

Your efforts are to be commended. We believe that there could be an extension of the effort you started here, and that the process could be simplified. On the basis of our review of this legislation and some research that we have been doing in the Department of the Interior, we would oppose S. 1132 as written.

Thank you very much. I offer my complete statement.

[The prepared statement of Mr. Carruthers follows:]

Statement of Garrey E. Carruthers, Assistant Secretary for Land and Water Resources, Department of the Interior before the Senate Subcommittee on Water and Power of the Committee on Energy and Natural Resources on S. 1132 - To Amend the Federal Power Act to Specify the Annual Charges for Projects with Licenses Issued by the Federal Energy Regulatory Commission for the Use of Federal Dams and Other Structures, July 25, 1983

Mr. Chairman, members of the Subcommittee, on behalf of the Department of the Interior, I am pleased to appear here today to comment on S. 1132. This bill would amend the Federal Power Act by specifying an annual charge of $1 per kilowatt of installed capacity and one-half mill per kilowatt hour of energy produced by hydroelectric projects with licenses issued by the Federal Energy Regulatory Commission for the development of hydroelectric power at a Federal dam or other structure.

In the past, there has been very little hydroelectric development by non-Federal entities at Bureau of Reclamation structures and facilities. However, there has been increasing interest in private development at Bureau of Reclamation sites and we want to encourage this interest. This legislation may have an impact on such development as it takes place in the future and on the fees collected from such development. It is important that we provide a reasonable return to the Federal Government for its investment. Therefore, we oppose S. 1132 because it appears to preclude this reasonable return.

We want to review closely the discussion today on this bill as well as comments submitted to the Federal Energy Regulatory Commission on a related proposed rulemaking and other possible alternative approaches.

STATEMENT OF MAJ. GEN. JOHN F. WALL, DIRECTOR OF CIVIL WORKS, OFFICE OF THE CHIEF OF ENGINEERS, U.S. ARMY CORPS OF ENGINEERS

General **Wall**. Mr. Chairman, mine may be a little longer, but I will begin.

The **Chairman**. Mr. Carruthers' was short and sweet.

General **Wall**. Mine may be a little longer, not as sweet, but just about the same.

I would like to commend this committee's efforts and you, Mr. Chairman, for considering new guidelines for the assessment of charges which non-Federal FERC licensees must pay for the use of Federal projects. New guidelines might help remove some of the uncertainty that currently faces potential hydroelectric developers and would facilitate their evaluation of economic feasibility.

Before I comment specifically on S. 1132, I would like to summarize the corps'experience and current efforts in the development of hydroelectric power. I do so in an effort to provide relevant background information and to put my views on S. 1132 in perspective.

The Corps of Engineers is the Nation's largest single producer of hydroelectricity, accounting for about 30 percent of its hydroelectric energy, and about 4 percent of its total electric energy.

Under provisions of the Flood Control Act of 1944 and other acts, electric power and energy generated at corps' projects which is surplus to project needs is turned over to the Secretary of Energy for marketing. Power marketing agencies of the Department of Energy establish rates to recover the cost of producing and transmitting the power, including repayment with interest of the allocated Federal investment over a 50-year period.

We fully support the development of sound, justified hydroelectric facilities. Increased power capacity through the construction of new or enlarged facilities, if properly implemented, would increase system efficiencies, reduce consumption of nonrenewable resources and reduce our dependence on oil imports and provide a dependable, safe, and efficient source of energy in the future.

Regarding the development of hydropower by non-Federal interests through the FERC licensing procedures, I would like to make several points.

First, we encourage the development of hydroelectric facilities by non-Federal interests. Projects designed and financed in this manner assuredly are worthy financial investments and responsive to local and regional needs.

Second, non-Federal hydroelectric development at, or affecting Federal projects must be accomplished in a manner that protects the public interest. In this regard, I must emphasize that safeguards such as those contained in the current memorandum of understanding between the Federal Energy Regulatory Commission and the Department of the Army must be protected.

Third, S. 1132 would provide for the assessment of annual charges to include "unreimbursed" Federal costs as well as a specified annual charge. The bill is unclear on what is considered an "unreimbursed cost."

In addition, the level of annual charge would be different than described with procedures for determining such charges that are currently being considered by the FERC. We believe that it is reasonable that annual charges to the licensee result not only in a profit for the non-Federal investor but also in a return to the Government on its investment in a structure. In this matter, however, the FERC is presently reviewing and receiving comments on a proposed rulemaking on this issue.

As mentioned earlier, no legislation should prohibit agreements between a Federal agency and a potential non-Federal interest on financial responsibilities associated with the construction of hydroelectric facilities at a Federal dam. For instance, considerable cost savings to the licensee can be realized in the concurrent construction of a powerplant and a Federal structure. Federal construction agencies should not be precluded from sharing these savings as well as recovering a portion of joint project costs, as would be the case of Federal construction of the power facility.

The annual charge established by the bill does not recognize the variation in savings possible at different locations, nor does it recognize the joint project costs which could reasonably be allocated to hydropower.

We would object to enactment of S. 1132 for these reasons, especially, Mr. Chairman, unless we could negotiate agreements with non-Federal interests on corps' dams and also because it places a ceiling on the charges that could be placed on the use of Federal facilities.

Therefore, we would object to it for the reasons I have stated.

This concludes my statement, Mr. Chairman. Thank you very much.

[The prepared statement of General Wall follows:]

Statement For The Record

By

MAJOR GENERAL JOHN F. WALL

Director of Civil Works, Office of the Chief of Engineers

Before The

Committee on Energy and Natural Resources

United States Senate

25 July 1983

S. 1132, A Bill to Amend the Federal Power Act
To Specify the Annual Charges for Projects with Licenses
Issued by the Federal Energy Regulatory Commission for
The Use of Federal Dams and Other Structures

Mr. Chairman, and Members of the Committee. I am Major General John F. Wall, Director of Civil Works for the Army Corps of Engineers, Office of the Chief of Engineers. I am pleased to be here to discuss, on behalf of the Department of the Army, S. 1132, a bill that would specify the annual charges for projects licensed by the Federal Energy Regulatory Commission for the use of Federal dams and other structures, including those of the Corps of Engineers.

I would like to commend this Committee's efforts and you, Mr. Chairman, in considering new guidelines for the assessment of charges which non-Federal F.E.R.C. licensees must pay for the use of Federal projects. New guidelines might help remove some of the uncertainty that currently faces potential hydroelectric developers and would facilitate their evaluation of economic feasibility.

Before I comment specifically on S. 1132, I would like to summarize the Corps' experience and current efforts in the development of hydroelectric power. I do so in an effort to provide relevant background information and to put my views of S. 1132 in perspective.

The Corps of Engineers is the Nation's largest single producer of hydroelectricity, accounting for about 30 percent of its hydroelectric energy, and about four percent of its total electric energy. Under provisions of the Flood Control Act of 1944 and other acts, electric power and energy generated at Corps projects which is surplus to project needs is turned over to the Secretary of Energy for marketing. Power marketing agencies of the Department of Energy establish rates to recover the cost of producing and transmitting the power, including repayment with interest, of the allocated Federal investment over a fifty-year period. The authorization of hydroelectric facilities with Federal financing and non- Federal reimbursement over time was appropriate during the formative years of our nation's water resources development. However, with increasing Federal deficits and an emphasis on greater non-Federal participation in decision making, the traditional pattern of Federal financing is no longer appropriate. Therefore, this Administration has committed itself to supporting legislation and developing policies which maximize non-Federal participation in the selection and financing of future water resources development projects. I believe that any legislation affecting the licensing of non-Federal hydroelectric development must recognize this commitment and must not preclude negotiations with potential non-Federal participants in hydroelectric projects. I will address this in more detail later in my testimony.

We fully support the development of sound, justified hydroelectric facilities. Increased power capacity through the construction of new or enlarged facilities, if properly implemented, would increase system efficiencies, reduce consumption of nonrenewable resources, and reduce our dependence on oil imports and provide a dependable, safe, and efficient source of energy in the future.

Regarding the development of hydropower by non-Federal interests through the FERC licensing procedures, I would like to make several points.

First, we encourage the development of hydroelectric facilities by non-Federal interests. Projects designed and financed in this manner assuredly are worthy financial investments and responsive to local and regional needs.

Second, non-Federal hydroelectric development at or affecting Federal projects must be accomplished in a manner that protects the public interest. In this regard, I must emphasize that safeguards such as those contained in the current Memorandum of Understanding between the Federal Energy Regulatory Commission and the Department of the Army must be protected. This MOU requires that hydroelectric development be compatible with authorized project purposes; that Congressionally authorized project functions not be significantly affected; that the Corps approve the design, construction, and operation of facilities which would affect the structural integrity or operational adequacy of the structures; and that the Corps be reimbursed for all reasonable costs associated with its review, approval, and inspection activities, which is not a charge for the use of a Government facility.

Third, S. 1132 would provide for the assessment of annual charges to include "unreimbiursed" Federal costs as well as a specified annual charge. The bill is unclear on what is considered an "unreimbursed cost." In addition, the level of annual charge would be different than described with procedures for determining such charges that are currently being considered by the F.E.R.C. We believe it is reasonable that annual charges to the licensee result not only in a profit for the non-Federal investor but also in a return to the Government on its investment in a structure. In this matter, however, the F.E.R.C. is presently reviewing and receiving comments on a proposed rulemaking on this issue.

As mentioned earlier, no legislation should prohibit agreements between a Federal agency and a potential non-Federal interest on financial responsibilities associated with the construction of hydroelectric facilities at a Federal dam. For instance, considerable cost savings to the licensee can be realized in the concurrent construction of a power plant and a Federal structure. Federal construction agencies should not be precluded from sharing these savings as well as recovering a portion of joint project costs, as would be the case with Federal construction of the power facility. The annual charge established by the bill does not recognize the variation in savings possible at different locations, nor does it recognize the joint project costs which could reasonably be allocated to hydropower. We would object to enactment of S.1132 for these reasons and because it places a ceiling on the charges that could be placed on the use of Federal Facilities.

This concludes my statement, Mr. Chairman. I will be glad to respond to any questions you may have.

The CHAIRMAN. Thank you very much.

General WALL. Yes, sir.

The CHAIRMAN. Ms. Sheldon, in the event that we went to a fixed charge, do you see the necessity for having some kind of an adjustment mechanism in the event that the fixed rate would render uneconomic some marginal projects?

Ms. SHELDON. Yes, I would, Mr. Chairman. I think it would be wise if you do go to a fixed charge to have a mechanism so that the Commission could defer charges on some projects for 5 years, or whatever portion of time is necessary. I think that you could have a deferment. I think, if you wish, you could also have an exemption.

The CHAIRMAN. Now, Secretary Carruthers, in your testimony you noted that the Department opposes the bill on the grounds that it doesn't provide the Federal Government with reasonable rates of return on its investment. What rate of return on investment does the Department consider to be reasonable?

Mr. CARRUTHERS. We are more concerned about procedure than the exact rate. Our concern is that if you establish a fixed rate of return right now, that it would probably have to be adjusted over time. We feel that this is the place where laws are changed and that logic suggests a much simpler system than the one that has been proposed.

The CHAIRMAN. What could be more simple than a flat rate?

Mr. CARRUTHERS. With the price of power changing over time, the amount that would be considered a reasonable return also changes, and could not be reflected in a flat rate, Mr. Chairman.

The CHAIRMAN. That doesn't make it simpler, does it, Mr. Carruthers?

Mr. CARRUTHERS. The system that I would propose could reflect changes in the value of power without having to change the flat rate on a regular basis.

The CHAIRMAN. You are assuming because a flat rate is inflexible that it has to be constantly changed.

Mr. **Carruthers**. With changes in the value of power, I would think there are demands to do that.

The **Chairman**. If you assume that it is not going to be changed constantly, then is this more simple or more complex, Mr. Carruthers, than adjustments?

Mr. **Carruthers**. If you're absolutely inflexible about changing it, obviously putting it in the statute and walking away, it is by far the simplest system. The value of power and the amount of power production vary over time. We believe that something like a royalty rate can accommodate both the variation in the production of power and the price of power and generate a reasonable return to the Federal Government.

Calculations show that the flat rate proposed in this legislation generates a return which is similar to the average of current annual charges assessed by the Federal Energy Regulatory Commission for the use of Federal sites. However, an average does not reflect the variation in the value of power and in the generation of power site by site.

The **Chairman**. Would you have it, in every instance, set by bid, or would you have it set by regulation?

Mr. **Carruthers**. I think, in my professional judgment, that you would approach this question by looking at the difference in the value of the sites. Clearly, some sites are worth more than other sites in the production of hydroelectric power. Some may be 6-to-1 benefit cost or 1-to-1. If you bid sites, the bidding system would pick up the differences in value. Bidding for the site would be used in addition to a fixed royalty.

The **Chairman**. Fixed in the bid?

Mr. **Carruthers**. Yes; you would establish the royalty in advance and it would probably then be the same for all sites. The difference in value of sites would be picked up in the bidding system. The royalty would provide that annual increment that would be forthcoming to the Federal Government.

The advantage of using a royalty, it seems to me, is that it will accommodate both changes in the production of power and changes in the price of energy.

The **Chairman**. A fixed royalty that is based upon what, Mr. Carruthers?

Mr. **Carruthers**. Gross revenues of power generation.

The **Chairman**. So it is variable according to revenue?

Mr. **Carruthers**. The annual charge would be calculated as a fixed percentage of gross revenue. The annual charge would vary depending on the amount of power you generate and the value of the power.

The **Chairman**. It is not fixed?

Mr. **Carruthers**. The royalty is fixed, yes.

The **Chairman**. Fixed by formula?

Mr. **Carruthers**. No, sir.

The **Chairman**. Is variable in its amount?

Mr. **Carruthers**. No; I would fix the royalty rate at some rate and let it accommodate the changes in the amount of power generated and the price.

The CHAIRMAN. You are confusing me. Fixed implies to me it is fixed and unchanged. You are saying that it is fixed but changeable.

Mr. CARRUTHERS. No; Let us just assume that we have a 5 percent royalty rate that is fixed.

The CHAIRMAN. Five percent of what?

Mr. CARRUTHERS. Of revenues generated at the powerplant. That is fixed, the 5 percent.

In a good year, a high production year, the power production would increase and the price may increase as well. The 5 percent royalty would increase the income to the Government considerably. By the same token, if the power production in that plant or the energy prices decrease, that decrease in revenue is also shared by the Federal Government with whoever is operating that power plant.

The CHAIRMAN. Under your suggestion, would that royalty be a percentage of gross receipts or net receipts?

Mr. CARRUTHERS. Gross receipts.

The CHAIRMAN. Gross receipts?

Mr. CARRUTHERS. Yes; there is also another advantage in giving the operator of the powerplant some certainty as to how much of the revenue they have to operate on in the future. We don't need to go through the other complex calculations of the current system or under some of the current systems, Mr. Chairman.

The CHAIRMAN. How long would this be? Would this be a license or a contract? What are they bidding on when they bid?

Mr. CARRUTHERS. The right to be on the site.

The CHAIRMAN. For how long?

Mr. CARRUTHERS. Well, I think that we have to give that license for a long period of time. Obviously, you'd have to give the license sufficient time for them to take care of all their investments. I don't know what FERC does now when they license. I don't know what the license tenure is.

The CHAIRMAN. Under the Federal Power Act it is 50 years. Is that what you had in mind?

Mr. CARRUTHERS. I don't think that we considered the length of the time, other than the length of time necessary for the company to make the investment and to recapture its investment and make a profit.

The CHAIRMAN. The variable in the cost to the licensee would be in the bonus bid up front?

Mr. CARRUTHERS. Yes; that would be the way that you would select the institution to operate on the Federal site.

The CHAIRMAN. There are a number of variables other than just the market. A lot of it is variable with respect to Government regulations. Would you include in the contract some adjustment mechanism or some guarantee against Government regulations?

Mr. CARRUTHERS. I don't believe that, in contracting, we should change the rules after that contract is executed. I believe that once the contract is executed that company ought to play by those rules of the game. We shouldn't do that other than by statutory change. The rules and the regulations of that contract should be held in effect until such time as the contract expires.

The CHAIRMAN. You note in your testimony the fact that there has been very little hydroelectric development by the non-Federal entities at Bureau of Reclamation structures. I assume that you start from the premise that is desirable to develop whatever is economically developed at those sites.

Mr. CARRUTHERS. Absolutely. We recommend that. We are constantly seeking developers who might want to develop sites that have potential.

The CHAIRMAN. Does that indicate also that in order to get it done, if it had been an obvious economic winner all along, the Federal Government probably would have done this?

Mr. CARRUTHERS. Well, that is not always the case. We have a major hydroelectric opportunity at the Navaho Dam in New Mexico. Somewhere along the line we failed to authorize hydroelectric development on the site, although we built the penstocks for hydroelectric power development. Now there is a contest between an Indian tribe and a city over who might develop that power. This is clearly a case where perhaps those two people ought to bid for it and return something to the Government.

The CHAIRMAN. Is it the exceptional case or the usual case that it is clearly economic today or has been for the last 10 or 15 or 20 years for the Government to do it, but they just failed, for some reason, to do it?

Mr. CARRUTHERS. I don't think that there has been much enthusiasm in the Bureau of Reclamation until recently for pursuing hydroelectric power development on the dams that needed to be retrofitted. There seems to be greater enthusiasm for the private sector to do it in the 2½ years that I have served in this administration. A lot of people have approached us about the possibility of developing hydroelectric facilities at Bureau of Reclamation sites.

The CHAIRMAN. That is true, certainly. As energy costs have risen and there is alternative energy, this changes the economics of the operation.

If, indeed, those were submarginal, and that is the case in many instances, such as the Palisades Dam in Idaho on the Idaho-Wyoming border, and it was not economic to put the power facilities on this when the dam was built. The change in the cost of the market value of electricity has not rendered that economic. There is a question of whether or not the Federal Government will build it or whether this will be built by a non-Federal entity. That is more typically the case, I believe, than the other possibility that we simply knew it was a good idea but we never got around to doing it on the Federal level. If that is true, would you not agree that if we raise the cost to the degree that we raise the cost of doing it, we render some to be subeconomic?

Mr. CARRUTHERS. Yes; I think the royalty rate, in particular, would be a sensitive factor. Our experience in other energy leasing programs has taught us that, as you adjust the royalty rates, you quickly adjust profitability of any enterprise.

The bonus bid, generally, is where we select the actual enterprise that is going to develop the site, and I would not think that would be a deterrent to development, Mr. Chairman.

The CHAIRMAN. Aren't there two factors that inhibit the non-Federal development of this, or maybe three? I was, or the one that

I added in the three, it was the bureaucratic inertia that says, "That's my dam. Stay away." Inertia may be more positive than just that.

There are two things. One is economics and the other is the regulatory or governmental policy uncertainty. Do you agree?

Mr. CARRUTHERS. I think so. That is why we promote simplifying the relationship between the Federal Government and any entity as much as we possibly can. The comments that we made to FERC on their proposed rulemaking suggest just that. Developers need certainty. We would like to simplify the system to avoid any excesssive reporting requirements or unnecessary calculations which could be burdensome to developers.

[Subsequent to the hearing Mr. Carruthers submitted the following:]

ALTERNATIVES FOR DETERMINING ANNUAL CHARGES FOR THE USE OF FEDERAL HYDROPOWER SITES

SUMMARY

The Secretary of the Interior has primary authority over the hydropower development of a site when this is authorized by Congress as a project feature. In these cases, the Secretary may establish a power privilege charge. Where Congress has not expressly authorized Federal hydropower development, a non-Federal entity may develop the site. Under Section 10e of the Federal Power Act, the Federal Energy Regulatory Commission (FERC) is charged with setting reasonable annual charges for the use of Federal hydroelectric sites by non-Federal entities. This paper examines alternatives for calculating this annual charge.

Alternatives are evaluated using the following criteria: (1) economic efficiency, (2) return to the Federal Treasury, (3) administrative efficiency, (4) removal of uncertainty, and (5) acceptability to the power industry. Because of the nature of the demand and marginal cost curves, there is little difference in economic efficiency among the alternatives for setting annual charges. The major differences among alternatives are based on the other four criteria.

The alternatives examined in this paper are:

1. Fifty percent of regionalized net benefits. This alternative is currently being proposed by FERC as a change in the regulations for determining annual charges. It is a four step approach which involves: (1) determining on a regional basis the annual cost of power from the least expensive alternative power source (power value) and using this as the measure of benefits; (b) determining the annual cost of hydroelectric project power (project powerhouse costs) using actual project construction costs; (c) determining net benefits by subtracting powerhouse costs from power benefits; and (d) charging the licensee 50 percent of the levelized net benefits for the privilege of developing hydroelectric power at a Government dam or other structure.

2. Flat rate charge. This alternative would charge a fixed dollar amount per kilowatt of installed capacity and a fixed mil amount per kilowatt hour of power produced. This is the approach suggested in S. 1132 which proposes an annual charge of $1 per kilowatt of installed capacity and one-half mil per kilowatt hour of energy produced.

3. Percentage of net revenues. This alternative would base the annual charge on a fixed percentage of the actual net revenues accruing to the developer of a site.

4. Percentage of gross revenues. This alternative would base the annual charge on a fixed percentage of actual gross revenues accruing to the developer of a site.

5. Percentage of the power produced (royalty). This alternative would make the annual charge some fixed percentage of the power produced

by the project, similar to the method used in oil and gas leases. The power could be used by the Government for its own purposes, marketed by the Federal power marketing agencies, or marketed by the developer for the Federal Government.

It is recommended that annual charges be determined using the royalty method. The royalty method is conceptually the same as the percentage of gross revenues method (alternative 4) and would cover not only projects where revenue is produced, but also projects in which the developer uses the power for other project purposes, such as irrigation districts, and no revenue is produced.

Alternative 1 is not desirable because it is much more complex than the other alternatives and charges are difficult to calculate. It would not only increase the administrative burden, but would also increase the uncertainty to developers over the present method of assessing annual charges. Initial indications are that this alternative is viewed as very unfavorable by the power industry. The returns to the Treasury under this alternative would probably be higher than for any of the other alternatives.

Alternative 2 is the most acceptable to the power industry. It is easy to calculate and use in any feasibility analysis and would be very easy to administer. Returns to the Treasury would probably not be as great as using alternative 1. The Government would not share in any increases in power rates and the developer could be excessively burdened by any decrease in power rates.

Alternative 3 would entail a large annual administrative burden for FERC in the form of compliance checks probably resulting in larger administrative costs than any other option. This alternative would also weaken the incentive to control costs. Returns could be approximately equal to the returns under alternative 1 over the life of the project. For example, if the percentage were fixed at 50 percent of net revenues, this should be approximately equal to 50 percent of net benefits. The Government would share in any increases or decreases in the value of electricity. Annual charges would be based on actual rather than estimated data. This alternative is not viewed favorably by the power industry.

The alternatives for setting the annual charge considered in this paper do not ensure that the lowest cost producer receives the site. FERC issues the permit to study the site on a first-come-first-served basis. The permittee has first priority at the license stage if the permittee's plan is equally well adapted to the site. It is recommended that site selection be determined using a bonus bid with the highest bidder receiving the license to develop the site. Because the permittee has priority at the license stage, this bidding scheme for site selection is contrary to existing statutes. It would take a statutory change to permit this type of bidding. Bidding the site would ensure that the lowest cost producer received the site, would extract some of the economic rent pertaining to a site, and would make the process of selecting the developer compatible with the procedures used in leasing other federally-owned resources.

I. Introduction

The purpose of the Federal Energy Regulatory Commission (FERC) Rulemaking (RM83-13-000) is to amend the regulations governing annual charges for hydroelectric power projects that use Federal sites. It proposes to switch from a case-by-case calculation of annual charges to a generic formula-based approach. Although a generic approach is sought, many of the necessary computations are still on a case-by-case basis. It would continue FERC's procedure of assessing a charge equal to one half of the net benefits (project benefits less costs), but would switch from a determination of benefits based on site-specific power values and an estimate of costs to a formula-based calculation of benefits and to actual project costs. Benefits under this proposal would still be calculated on a case-by-case basis, but using formulas which are based on regional power values. The annual charge would be adjusted annually for inflation using the Gross National Product deflator. This charge would apply to power producers at Federal sites where power is not an authorized purpose. Included are projects to be licensed in the future, recently licensed projects with license fees yet to be determined, and adjustments of annual charges. Payments by project sponsors to the Bureau of Reclamation for lease of power privilege or repayment obligations would not be credited against this charge nor would any portion of the revenue received by FERC be allocated to the Reclamation Fund.

FERC contends that the proposed rule will avoid increased costs to consumers of electric power, reduce the time and resources expended by FERC and its licensees to calculate the annual charge, and expedite the licensing process. The proposed rule does not affect the process used by FERC to determine which non-Federal entity is selected to develop the site.

In this paper several alternative procedures for assessing the charge for the use of Federal sites are evaluated and two procedures are recommended for consideration, bidding the site and payment of a royalty. Bidding the site would also change the process by which the licensee is selected. Bidding the site and payment of a royalty would be similar to the procedure that is currently used in gas, oil, and coal leasing. Interior believes that these market-oriented alternatives will be economically efficient, fair to consumers and potential licensees, and less burdensome to administer than either the FERC proposed rulemaking or the current FERC permitting process. However, a change in the Federal Power Act would be necessary to allow bidding for the license.

II. Background

The Secretary of the Interior has primary authority over the hydropower development of a site when hydropower is expressly authorized by Congress (18 CFR 4.30). In those cases where he has development authority, the Secretary may establish a power privilege charge (section 9(c) of Reclamation Project Act of 1939, 43 U.S.C. 485h (c)).

In cases where Congress has not authorized Federal hydropower development at a site, a non-Federal entity may develop the site (section 4(c) and 23(b) of the Federal Power Act, 16 U.S.C. §§ 797(e), 817(b)). FERC determines which non-Federal entity is issued the permit to study the site, which entity is issued the license to develop the site, and establishes a license fee (section 10(e) of the Federal Power Act).

When the site at issue involves the use of a Bureau facility, the Secretary can assess a power privilege charge in addition to FERC's annual charge. Furthermore, FERC must obtain approval of its charge from the Secretary. Outside of requiring that the FERC license contain conditions necessary for adequate protection and utilization of the project, the Secretary has no input on selection of permittees and licensees. The process is determined by FERC.

The Federal Power Acts gives FERC the authority to issue licenses to citizens of the United States for the purpose of constructing, operating, and maintaining dams, conduits, transmission lines, and powerhouses in any of the streams or other bodies of water over which Congress has jurisdiction to regulate commerce, including surplus water or water power from any Government dam. FERC also has the authority to issue preliminary permits for the purpose of enabling applicants for a license to secure the data to prepare maps, plans, specifications, and estimates of cost as may be required for a full understanding of the proposed project. Each permit issued shall be for the sole purpose of investigating the development potential of a site. The permit also maintains priority of application for a license for a period not exceeding 3 years. It is not necessary to have a permit before applying for a license.

Even though one entity has received a permit to study a particular site, another entity may file for a license to develop that site. However, the Federal Power Act requires that the license be issued to the permit holder as long as the permittee's plans are equally well adapted to develop the site or will be made equally well adapted. Due to the permittee's priority right, the permittee would also have priority over a preference entity at this stage of the licensing process.

Preference will be given to States, municipalities, and other public entities in issuing permits as provided in the Federal Power Act and for licenses where no permit has been issued. However, States, municipalities, and other public entities do not have preference over a permittee as long as the permittee's plan is equally well adapted to the specific site. Preference to the site granted to States, municipalities, and other public entities under the Federal Power Act should not be confused with the preference that these public entities have to power produced by the Federal Government under the Reclamation Project Act.

Thus, it appears that a bidding process could not be utilized at the licensing stage since the permittee has priority for development.

However, bidding could possibly be used at the time of application for a permit as long as competition would be avoided between preference and non-preference entities. The problem with introducing bidding at this stage is that most of the good sites already have permits issued.

In an effort to determine the impact of the proposed FERC rule and of possible alternatives to it, information was collected from recent hydroelectric power project status reports provided by the Bureau of Reclamation's Mid-Pacific, Pacific Northwest, and Upper Colorado regions. These regions contain the sites of most of the hydropower opportunities where license fee rules would impact on States in the Reclamation Service area. Data from the Pacific Northwest includes only those projects located at Bureau of Reclamation facilities, while the data from the other two regions includes all potential hydropower sites.

Table 1 shows the breakdown between preference and non-preference permit holders in each region expressed as a percentage of the total number of projects in that region. Preference customers hold the majority of the permits in the Upper Colorado, but only hold about 40 percent of the permits in the other two regions.

TABLE 1

Characteristics of Permit Holders at Hydropower Sites

Region	Number of Project Sites	Preference Customers (Percent)	Non-Preference Customers (Percent)
Mid-Pacific	821	42.3	55.9
Pacific Northwest	166	42.8	56.6
Upper Colorado	179	64.2	35.8

Table 2 analyzes the extent of license competition at hydropower sites where multiple applications have been filed. Effective competition for a license at a site exists when there are applications from either: (a) two or more preference customers, (b) two or more non-preference customers, or (c) multiple preference customers and one or more non-preference customers. Current law prohibits competitive bidding for licenses between preference and non-preference customers. This means that 111 sites for which multiple applications have been filed would be affected by bidding if the rule according priority to permit holders were changed. If a bidding procedure were established, it is possible that the number of applications would increase from this level.

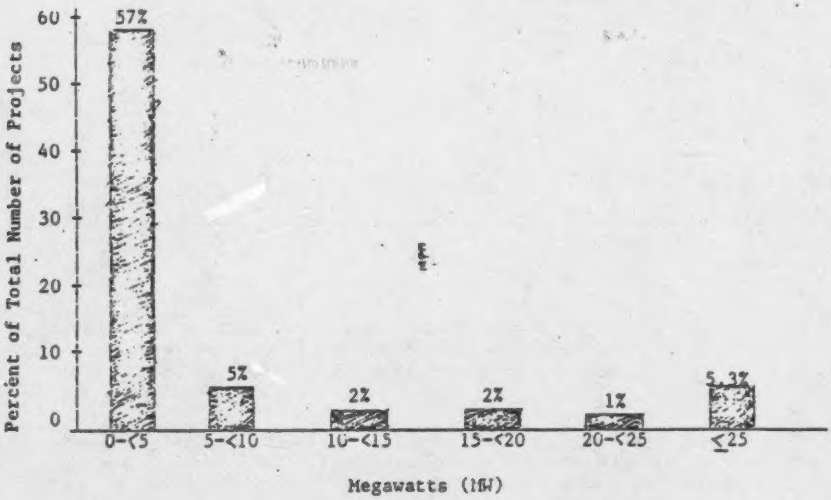
TABLE 2

Competition for Hydropower Sites

		Multiple Applicant Sites	
Region	Total Number of Sites	Single Preference Customer vs. Non-Preference Customer	Effective Competition
Mid-Pacific	821	44	58
Pacific Northwest	166	29	20
Upper Colorado	48	15	33

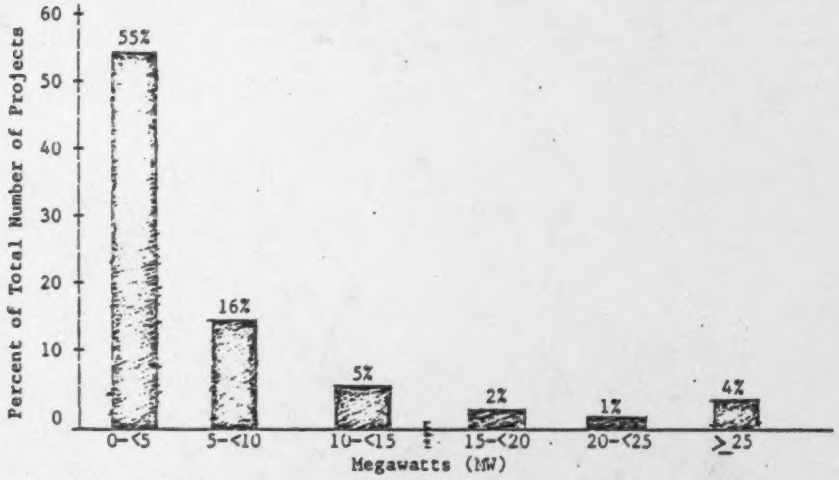
The capacities of the projects in the Mid-Pacific and Pacific Northwest regions are graphically represented to show how many projects have very small or very large potential power output. The bar graphs depict the capacities at which most projects would operate. It is clear that most of the hydrosites in the Mid-Pacific and Pacific Northwest regions are expected to have less than 5 megawatts of capacity. The remaining opportunities in both regions are similar except that there are significantly more opportunities between 5 or 10 megawatts in the Pacific Northwest region.

FIGURE 1. CAPACITIES OF PROJECTS IN THE MP REGION



NOTE: Several projects have extremely large capacities (up to 800 MW). The remaining 28 percent represents those potential projects whose capacities were not specified.

FIGURE 2. CAPACITIES OF PROJECTS IN THE PN REGION



NOTE: The largest capacity was 220 MW, with several others around 70 MW. The remaining 17 percent represents those potential projects whose capacities were not specified.

Figures 3 and 4 show that in the mid-Pacific and the Pacific Northwest regions, very similar patterns occur in the size distribution ratios between preference and non-preference customers at each capacity. The graphs reveal that in both regions, non-preference customers have more projects at the smallest capacity level (0-<5 MW) than preference customers. Preference customers dominate the higher capacity projects in both regions except at the 15-<20 MW level. However, the single highest capacity project in both regions belongs to a non-preference customer. Capcacities for the Upper Colorado region are not yet available.

FIGURE 3. PREFERENCE vs. NON-PREFERENCE CAPACITIES
MID-PACIFIC

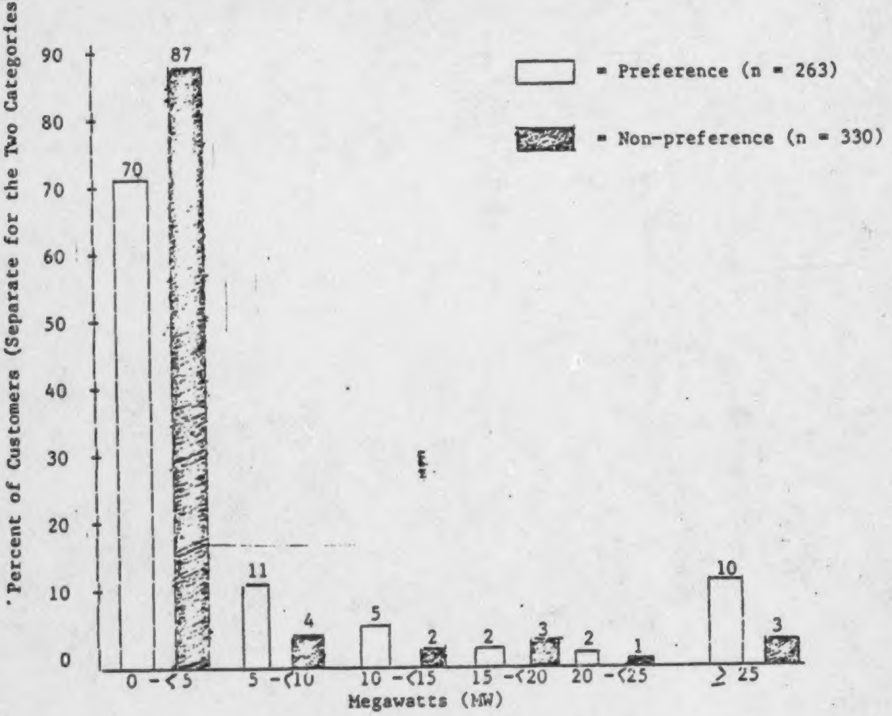
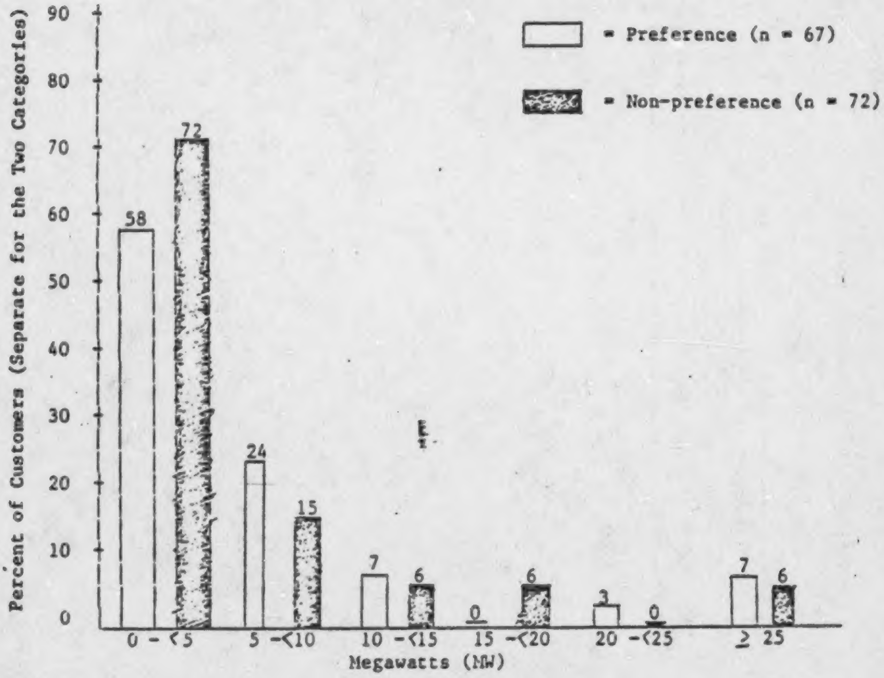


FIGURE 4. PREFERENCE vs. NON-PREFERENCE CAPACITIES
PACIFIC NORTHWEST



III. Options for Determination of Annual Charges and Site Selection

As described earlier, FERC's procedures for determining who develops the site and its procedures for determining the annual charge are independent. The selection of developer is made primarily on a first-come-first-served basis subject to a priority granted to preference customers. After granting the license, an annual charge of half of the net benefits (benefits less cost) is assessed. Under the proposed rulemaking, benefits are defined as the least cost alternative means of providing equivalent capacity for firm and non-firm energy. These benefits would be determined for each site using regional power values. Costs would be the actual construction outlays of the hydropower plant and the estimated operation, maintenance and replacement costs. The annual charge of half the net benefits would be adjusted annually by the Gross National Product deflator to maintain equal "real" values of the payments through time.

There are several options for calculating charges. Annual charges can be calculated as: (1) a flat rate based on plant capacity in kilowatts and the amount of energy generated in kilowatt hours, (2) a fixed percentage of net revenue, (3) a fixed percentage of gross revenue, or (4) a royalty or claim on some fraction of the energy produced. Alternatively, a lump sum entry fee can be employed either in place of, or in addition to, annual fees.

A standard approach used by the Federal Government to make finite fuel resources available for private development is to accept bids for the right of exclusive entry to the site and to retain the rights to a fixed percent of future production in the form of a royalty (e.g. 12-1/2 percent). Thus, the Federal Government could use the same basic approach to water power development that is used in developing its other resources. As mentioned above, the use of a bidding system at the license stage would require statute changes.

Evaluation Criteria

There are several criteria that should be considered in choosing an option for determining annual charges and choosing a non-Federal developer. Included are:

1. Economic efficiency — Does the option assure: (1) that the least cost producer receives the site and (2) that he produces all units that cost less than the value of the last unit of power produced? The consumer pays higher prices when the least cost producer does not receive the site. The economy foregoes power production when regulations prevent the developer from meeting the second part of this criterion.

2. Return to the Federal Treasury — Awarding the right to generate power at a Federal site is a public trust. This right is owned by the public at large. It should reasonably expect the highest possible return from transfer of this right to specific developers.

3. Administrative efficiency — Both the calculation of the charge and the selection of the developers should be carried out at the least cost to the Federal Government. The average number of permit applications filed with FERC for development of hydro sites increased from about four filings per year before 1978 to about 1800 filings in 1981 and has leveled off since then. With this kind of workload, it is essential that the process for setting annual charges be as simple as possible.

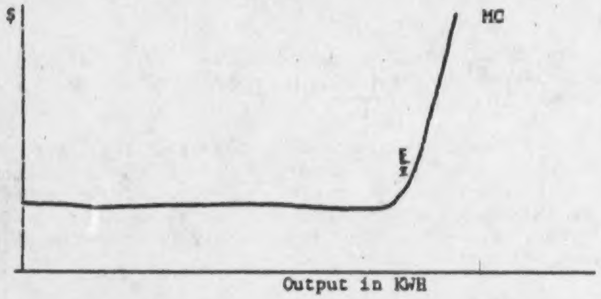
4. Removal of uncertainty -- An important component in the process of developing a site is the financial feasibility study conducted by a potential developer. Anything that delays the availability of data needed for the feasibility study or substitutes a variable factor for a firm number tends to add to the uncertainty and makes feasibility more difficult to determine. This tends to discourage the development of hydropower. Thus, the rules established for setting annual charges for the use of Federal sites should reduce uncertainty. All parties should have a clear idea of the rules of the game and these rules should be in place long enough so that anticipated returns can be realized from the private resources committed and can be reasonably estimated.

5. Acceptability to the power industry -- The procedures for calculating the charge and selecting the permittee should appear reasonable to the prospective investors or there will be disincentives to participate in the development of hydropower.

Factors to be Considered in Evaluating Economic Efficiency

To evaluate an alternative based on economic efficiency, the shapes of the marginal cost curves and the demand curves facing potential hydropower developers need to be considered. The marginal cost curves for hydro projects are nearly horizontal and probably approach zero until capacity is reached. At capacity the marginal cost is nearly vertical (figure 5).

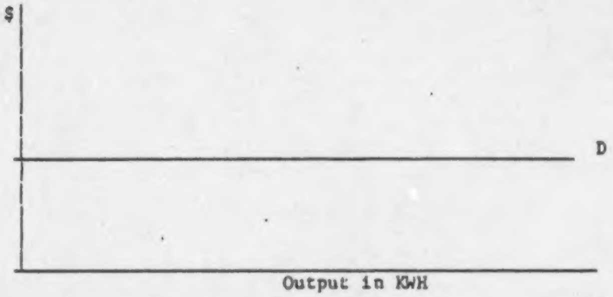
Figure 5. Marginal cost curve for a typical hydro project.



Below capacity, the additional cost of producing one more unit of energy is negligible.

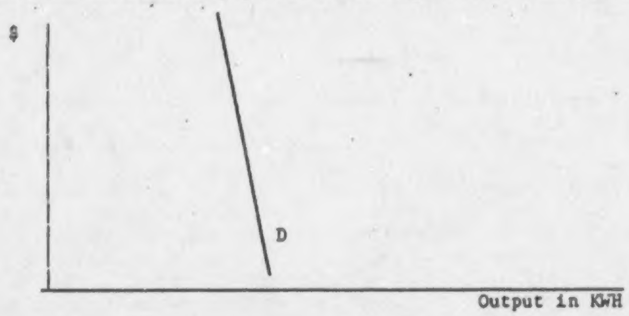
There are two different types of demand curves faced by hydropower developers. The first is the demand curve faced by a small power producer qualified under PURPA to sell power to utilities at cost avoided rates. To qualify, the power producer must have (1) a project of less than 80 megawatts, (2) use a renewable resource in power generation and (3) not have power production as its main purpose. The demand curve faced by such a small power producer is essentially horizontal, reflecting little control over the price received for the power marketed (figure 6). The small power producer gets the cost avoided rate (or more realistically a negotiated rate somewhat lower than the cost avoided rate) for all units of power that can be produced.

Figure 6. Demand curve faced by qualifying small power producer.



The second type of demand curve is one faced by a hydropower developer who is selling power to the consumers. The demand curve for electricity faced by these developers is very inelastic in the short run; i.e., quantity demanded is very unresponsive to price (figure 7). Given the existing stock of electrical appliances and equipment, consumers have a need for a certain amount of power regardless of price.

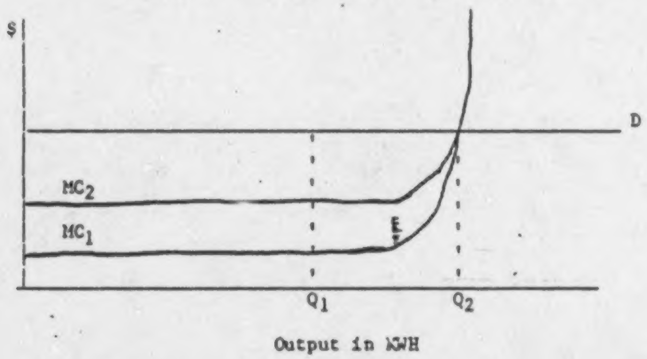
Figure 7. Demand curve faced by producer selling power to the public.



The shapes of these marginal cost and demand curves have some important implications for economic efficiency. Alternatives which would have the effect of shifting the marginal cost curve upward would have little or no effect on the quantity of energy produced.

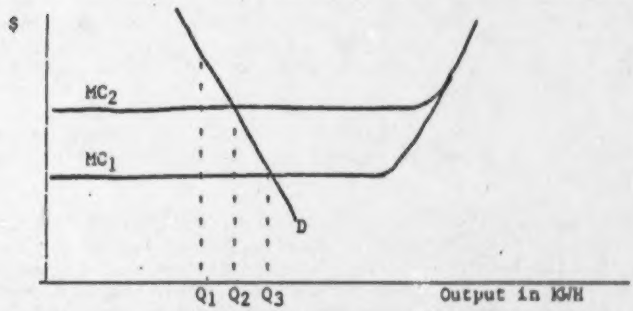
The impact on a PURPA qualifying small power producer can be explained using figure 8. Since hydro sites are typically not undersized when they are developed, the project produces all the electricity possible subject to the availability and flow of water. This means that the project is producing electricity at some level Q_1 less than capacity most of the time. Although the optimal economic solution would be to produce Q_2, rarely is the water available to produce at this level. If a regulation, such as a royalty, shifts the marginal cost curve from MC_1 to MC_2, the producer producing at Q_1 will still produce at Q_1. In fact, the producer will still produce Q_1 as long as the marginal cost curve does not shift so far upward as to lie above the demand curve. Thus, for qualifying small power producers, regulations which have the effect of shifting the marginal cost curve upward will result in little or no loss of economic efficiency since all units that cost less than the value of power will still be produced. However, at those times when the producer is at or near capacity, there will be some loss of economic efficiency since slightly less power will be generated.

Figure 8. Qualifying small power producer



The economic efficiency impact on producers selling power to the public can be explained using figure 9. There are two possibilities here; one in which there would be no economic efficiency losses and one in which the economic efficiency losses would be small. The case in which the economic efficiency losses would be small would occur if there were sufficient water flow to produce at Q_3. If a power charge were adopted which would shift the marginal cost curve from MC_1 to MC_2, the producer would produce Q_2, and there would be a small loss in economic efficiency. The more inelastic the demand curve, the smaller is the loss in economic efficiency. Since the demand for electricity is typically very inelastic, there would be little loss in economic efficiency in this case. If there were only sufficient water flow to produce at Q_1, a shift in the marginal cost curve from MC_1 to MC_2 would result in no loss in economic efficiency. The producer would still produce at Q_2.

Figure 9. Producer selling power to the public



In setting annual charges for the use of Government dams, other objectives stated in the Federal Power Act must also be considered. Charges must be set so that (1) the Government receives an adequate return for the use of its resources, (2) the price of power to consumers is kept as low as possible, and (3) the development of hydropower is encouraged. Clearly, some of these objectives are conflicting and tradeoffs must be made in establishing a process for determining actual annual charges. The higher the annual charge, the greater is the return to the Government. However, some forms of higher annual charges can be passed through to consumers in the form of higher prices through the rate making process. Also, some forms of higher annual charges tend to discourage the development of hydropower. As most recently expressed in PURPA, Congress seems to place the highest priority on the develoment of hydropower and keeping cost to consumers low.

IV. Alternatives for Setting Annual Charges for the Use of Government Dams

The first five alternatives assume that the developer is chosen according to current FERC procedures, generally the permittee receives the site.

Alternative 1. Fifty percent of regionalized net benefits

This alternative is currently being proposed by FERC. It is a four step approach which involves:

a. determining on a regional basis the annual cost of power from the least expensive alternative power source (power value) and using this as the measure of benefits;

b. determining the annual cost of hydroelectric project power (project powerhouse costs) using actual project construction costs;

c. determining net benefits by subtracting powerhouse costs from power benefits; and

d. charging the licensee 50 percent of the levelized net benefits for the privilege of developing hydroelectric power at a Government dam or other structure. Levelized means determining a series of uniform annual amounts which, over a specified period, would result in the same aggregate present value as a series of varying estimated annual amounts.

FERC proposes an extensive data collection and modeling effort to determine power values for between 18 and 20 regions nationwide. These data are to be updated annually.

Discussion: This proposed rule is complex. Significant staff time would be required to compile the necessary data and to calculate the regional power values. Additional time would be necessary to make all the necessary calculations for each project. Therefore, it is unclear how much savings there would be in administrative costs when compared with current FERC procedures. This proposed rule would take more expertise on the part of developers than is currently the case. It would almost ensure that a consultant would need to be retained to perform the annual charge calculations.

The use of actual project costs in determining the net benefit would mean that the actual annual charge would not be known to the developer until after the project was completed. Currently, the actual annual charge is determined during the licensing procedure and is known by the developer before project construction begins. Therefore, the proposed procedures would increase both uncertainty over the charges to be levied and would likely increase administrative costs both for the developer and for FERC. The additional cost and administrative burden would tend to discourage the development of hydropower at some sites.

The use of actual costs in determining net benefit would have a weaker incentive for developers to reduce actual project costs compared with current FERC procedures. The developer would realize 50 percent of the cost savings under this alternative, but would realize 100 percent of cost savings under the current FERC procedures.

Calculating estimated benefits using regional power values could be a real problem. A basic and fallacious assumption underlying this approach is that revenue potentials are similar for all energy producers within a region. Thus, this approach will work well only if the rate structures faced by projects within a region are fairly homogeneous. This forces a tradeoff administrative burden to FERC and the accuracy of estimated revenues to the developer. The larger the regions, the greater is the likelihood that they will lack homogeneity. The smaller the regions, the greater will be the administrative burden in calculating regional power values while revenue potentials will be more accurately measured.

The process of levelizing costs and benefits may be fine for analyzing project feasibility; however, it seems to be a poor basis on which to charge an annual fee. The process of levelizing spreads costs, which tend to be high initially and low thereafter, into the future. It also spreads revenues, which tend to be small initially and increase with time, back to the present. Charging one-half of the levelized net benefits could give a developer a severe cash flow problem, since actual costs and revenues would probably be quite different than levelized costs and revenues. The option to defer payment of annual charges during the first 10 years could mitigate this problem. However, the problem could be completely avoided if an alternate method of determining annual charges that more closely reflects actual annual costs and revenues were used.

The sharing of net benefits method proposed by FERC may not reflect the real world of hydroelectric power marketing. Under PURPA, qualifying small-scale power producers are entitled to sell hydroelectric power to public utilities at a rate equal to the cost the utility avoids by not generating or purchasing that increment of power. State public utility commissions have promulgated orders defining these "avoided costs" on a utility-specific basis. Avoided cost rates serve as a basis for negotiation between a small-scale hydroelectric developer and a public utility. In large measure, the hydroelectric developers' revenues are defined by the avoided cost rates. The method of determining annual charges proposed by FERC would base such charges on the theoretical value of the power, irrespective of the actual revenues obtained by a small-scale hydroelectric developer from the sale of that power. Therefore, FERC could simplify the calculation of annual charges by using the applicable avoided cost rate as a measure of benefits for plants which are qualified under PURPA. This would greatly reduce administrative cost of determining power benefits and would substitute an accepted market test for the value of power in place of a less certain regional calculation.

Analysis:

a. Economic efficiency: This alternative does not ensure that the least cost producer receives the site because the decision is based on first-come-first-served. The developer receiving the site does have the incentive to produce all units that cost less than the value of the power produced since the marginal costs faced by the producer are not altered by a fixed annual charge.

b. Return to the Federal Treasury: Higher than the current method. Being linked to the GNP deflator, returns to the Treasury will probably increase over time.

c. Administrative efficiency: This alternative is more complex than the current method and would result in increased administrative burden.

d. Removal of uncertainty: This alternative increases the uncertainty to developers over the present method used to assess annual charges because it is not determined until project completion.

e. Acceptability to power industry: Initial indications are that this alternative is viewed as very unfavorable by the power industy. The charges are difficult to compute under this alternative. This alternative is seen as discouraging the development of hydropower.

Alternative 2. Flat Rate Charge

This alternative would charge a fixed dollar amount per kilowatt of installed capacity and a fixed mil amount per kilowatt hour of power produced. This flat rate charge could be linked to some electricity rate index to ensure a fair return to the Government.

Analysis:

a. Economic efficiency: This alternative would not ensure that the least cost producer received the site. There would be little or no loss in output since all or almost all of the units that cost less than the value of the power would be produced, as explained above. Depending on the amount of the charge some of the more marginal projects would not be constructed.

b. Return to the Federal Treasury: Depending on the levels set revenues could approach but would probably not be as great as alternative 1. If a flat rate charge were used without indexing, the Government would not share in any increase in power rates and the developer could be excessively burdened by any decrease in power rates.

c. Administrative efficiency: This alternative is truly a generic approach and would be very easy to administer.

d. Removal of uncertainty: This alternative would remove all uncertainty about annual charges if it were not linked to an index and would still remove much of the uncertainty if annual charges were linked to an index.

e. Acceptability to power industry: Initial indications are that this alternative is very acceptable to the power industry. It is easy to calculate and use in any feasibility analysis. This alternative is viewed as encouraging the development of hydropower.

Alternative 3. Percentage of Net Revenues

This alternative would base the annual charge on a fixed percentage of the actual net revenues accruing to the developer of a site.

Analysis:

a. Economic efficiency: This alternative does not ensure that the least cost developer receives the site. There would be little or no loss in economic efficiency since the developer receiving the site has the incentive to produce all or almost all of the units that cost less than the value of the power produced.

b. Returns to the Treasury: Returns could be approximately equal to the returns under alternative 1 over the life of the project. For example, if the percentage were fixed at 50 percent of net revenues, this should be approximately equal to 50 percent of net benefits. The Government would share in any increases or decreases in the value of electricity. Annual charges would be based on actual rather than estimated data.

c. Administrative efficiency: The use of net revenue would entail a large annual administrative burden for FERC in the form of compliance checks probably resulting in larger administrative costs than any other option. This would also weaken the incentive to control costs.

d. Removal of uncertainty: Since annual charges are some known percentage of net revenues, this alternative would remove the uncertainty from the process of setting annual charges.

e. Acceptability to the power industry: This alternative would not be very acceptable to the power industry. The use of actual net revenues would require the developer of a site to maintain detailed cost accounts. One of the purposes of PURPA was to relieve them of this burden. Also, the valuation problem for power produced for internal use would exist.

Alternative 4. Percentage of Gross Revenue

This alternative would base the annual charge on a fixed percentage of actual gross revenues accruing to the developer of a site.

Analysis:

a. Economic efficiency: This alternative would not ensure that the least cost producer received the site. There would be little or no loss in output since all or almost all of the units that cost less than the value of the power would be produced, as explained above.

b. Returns to the Treasury: Returns would be greater than under alternative 2, but not as large as under alternatives 1 and 4. The Federal Government would share in any increases or decreases in the value of electricity.

c. Administrative efficiency: An annual charge based on percentage of gross revenue would be very easy to administer, although it would require more accounting data than alternative 2.

d. Removal of uncertainty: Since annual charges are some known percentage of gross revenues, this alternative would remove most of the uncertainty from the process of setting annual charges.

e. Acceptability to the power industy: Some marginal projects would be eliminated. The table below shows the benefit-cost ratio needed for a developer to break even on a project at different percentages of gross revenues.

Charges as a Percentage of Gross Revenues	Benefit-Cost Ratio Needed to Break even
0	1.00
5	1.05
10	1.11
15	1.18
20	1.25
25	1.33

With an annual charge of 5 percent of gross revenues, any project with a benefit-cost ratio of less than 1.05 would not be profitable and hence would not be undertaken. This table illustrates the tradeoff between increasing returns to the Government and the elimination of marginal projects. This alternative is viewed as the second most acceptable option by the power industry with alternative 2 being the preferred option. A valuation problem for power produced for internal use would exist.

Alternative 5. Percentage of Power Produced (Royalty)

This alternative would make the annual charge some fixed percentage of the power produced by the project, similar to the method used in oil and gas leases. The power could be used by the Government for its own purposes, marketed by the Federal power marketing agencies or marketed by the developer for the Federal Government.

Analysis:

This is similar to alternative 4 above and the same analysis would apply. This alternative is more general than option 4 because it would cover not only projects where revenue is produced but also projects in which the developer uses the power for other project purposes, such as irrigation districts, and no revenue is produced from the sale of electricity unless there is surplus power.

Alternative 6. Bonus bid or Entry Fee

This alternative would call for a bonus bid or entry fee which could be implemented separately or in addition to alternatives 2 through 5 above. Within certain restrictions explained below, the highest bidder receives the license to develop the site with payment required as a lump sum prior to construction commencing. The steps in the bidding process are as follows:

1. The first entity to apply for a permit to study a particular site would be awarded the permit. All information collected during this study would be publicly available.

2. All parties interested in submitting a bid for the license for a site would need to be qualified. FERC would qualify potential bidders under currently used criteria, e.g., financial ability, safety of the

project works and operation, environmental factors, suitability of the proposed project to the site, and any other factors deemed to be in the public interest.

3. Sealed bids would be submitted with the highest bid receiving the site subject to:

   a. A bid by a qualified preference entity eliminates all non-preference entities from the bidding.

   b. The permit holder has two choices if it is not the highest bidder:

      (1) Match the highest bid and be awarded the license. This does not apply if the permit holder is a non-preference entity and the highest bidder is a preference entity.

      (2) Be compensated for the cost of doing the feasibility study.

Discussion: The bonus bid serves the purpose of selecting who gets the opportunity to develop the site and would change the current practice of awarding the site on a first-come-first-served basis. The Government is compensated for the power privilege pertaining to a site both through the bonus and through the charges applicable under one of the alternatives 2 through 5 above.

Sites with higher benefit-cost ratios have higher profits. These higher profits, sometimes referred to as economic rent, may be viewed as unearned by the developer since they result from the characteristics of the site rather than from the resources or management ability of the developer. It could be argued that the Federal Government would not receive an adequate return on its resources from sites with high benefit-cost ratios if annual charges were set using alternatives 2 through 5. The FERC proposal, alternative 1, is an attempt to extract some of the economic rent pertaining to a particular site, but is not as satisfactory as bonus bidding which relies on market-based cost and revenue estimates. When there is potential competition a developer would have the incentive to bid a high proportion of his economic rent. Therefore, this alternative would result in the highest Federal revenue. Moreover, the lowest cost producer could bid more for the site than higher cost producers which would enhance economic efficiency by assuring the low cost producer gets the site.

Analysis:

a. Economic efficiency: This alternative would assure that the least cost producer receives the site. There would be no loss of economic efficiency since all of the units that cost less than the value of the power would be produced. This alternative ranks higher in economic efficiency than any other option considered.

b. Returns to the Treasury: Returns to the Treasury would depend on the number of bidders. With the threat of competition from even two or three bidders, a good deal of the economic rent pertaining to a site could be received.

c. Administrative efficiency: Administrative costs would be incurred in establishing the bidding process, in holding the sale, and in evaluating the bids, but would be negligible thereafter. The administrative costs of this alternative would probably be higher than alternatives 2, 4, or 5, but lower than 1 or 3. The increased administrative costs would be more than offset by the increased revenues received from the bonus bids.

d. Removal of uncertainty: A developer could not be certain of bidding the highest and receiving the site. However, each developer would know exactly what the cost would be if he were to receive the site, namely the amount bid.

e. Acceptability to the power industry: There does not seem to be any great enthusiasm for bidding on the part of the power industry and this would be a new concept for awarding sites to potential developers.

V. Recommendations

Absent legal and institutional constraints, it would be recommended that alternative 6 be adopted (competitive bidding) in conjunction with alternative 5 (annual fee as some fixed percentage of the power generated). Alternative 6, used in conjunction with alternative 5, would provide both a means of assuring the least cost producer is selected to develop a site and of extracting, in the limit, economic rent pertaining to a site not collected by the annual charge. The adoption of this combination of alternatives would result in a process which is economically efficient, ensures a reasonable return to the Government, and is easy to administer.

However, there are legal and institutional constraints to consider. Alternative 5 is in accordance with existing statutes. Unfortunately, alternative 6 is not. Section 5 of the Federal Power Act gives a preliminary permit holder a "priority of application for a license" for a period not to exceed 3 years. The preference granted under section 7(a) to municipalities, irrigation districts, etc., does not prevail over a permit holder's timely application for license, provided the plans are equally well adapted. Thus, the bonus bid would be contrary to the letter and intent of the Federal Power Act if it resulted in awarding the license to either a preference or a non-preference applicant because of a high bid when the permit holder's application is equally well suited. The use of any bidding program for the purpose of determining who receives the right to develop the site would take a revision of the Federal Power Act even when the program recognizes the priority of the preference customers. Thus, it is not possible under existing statutes to ensure that the least cost developer receives the site. This means as previously mentioned, that the consumer is not receiving the lowest possible prices for power and that the Treasury is not guaranteed maximum returns.

There are two courses of action that could be adopted; one feasible under existing statutes and the other requires a change. The first is to set annual charges based on a fixed percentage of power produced instead of either the current or proposed FERC procedures. This option is easy to administer, removes the uncertainty on the part of developers, and requires no changes in current statutes. No attempt would be made to extract economic rent pertaining to a site in excess of this annual charge. Experience with some Government leasing programs indicates that the bulk of the returns to the Treasury are generated by the royalty rather than by the bonus. Thus, adoption of this alternative assures a reasonable return to the Treasury for the use of the site. An analysis of data from actual projects found that in most cases an annual charge based on 5 percent of the gross revenues was approximately equal to the actual annual charge computed according to current FERC procedures.

The second course of action is to press for limited revision of the Federal Power Act to allow for the possibility of using bonus bids to detemine who receives the site in combination with a royalty. This would make it possible to ensure that the lowest cost producer received the site and to extract any economic rent pertaining to a site. It would increase returns to the Treasury and make the leasing of Federal dams compatible with the procedures used in leasing other federally-owned resources. This second course of action is the one which we prefer.

The CHAIRMAN. General Wall, you note in your testimony that the corps encourages the development of hydroelectric projects on Federal facilities by non-Federal developers.

In your opinion, does S. 1132, that is, is S. 1132, in any way, inconsistent with those objectives?

General WALL. In my personal opinion, I think, no, that it does encourage development. That is a straight-out answer. If I could expand on that, we think it needs a little bit more money back to the Government to bear the cost of it.

The CHAIRMAN. I want to return to that in just a moment, General.

General WALL. Yes, sir.

The CHAIRMAN. I want to return to that in just a moment, if I may, with all three witnesses.

General WALL. OK.

The CHAIRMAN. Now, you note in your testimony that the corps objects to enactment of S. 1132 on the grounds that it places a ceiling on charges that could be levied. Do you object to the enactment of a limit, or are you concerned that the limit established by S. 1132 is too low?

General WALL. It's the latter, sir. We would defer to FERC since they are currently engaged in rulemaking on the subject of annual charges, as to what they should be. We generally agree with their proposed approach, which basically calls for retention of the sharing of net benefits with some modification.

As I understand it, the provisions of S. 1132 is only a dollar per kilowatt capacity and one-half mill per kilowatt hour produced, which we think is a token amount and this is substantially below the amount that would be collected under the FERC proposal.

As a matter of fact, we believe that FERC should modify its proposed rules to require that non-Federal development be assigned costs at least equal to that which would have been assigned if the power facilities were federally developed.

So, the answer to your question is that we believe it is too low.

The CHAIRMAN. Would that be done in the event of the corps projects where you would assign a value and that would be the charge?

General WALL. Whatever FERC would come up with in its rulemaking, yes, sir.

The CHAIRMAN. You suggest that whatever the Federal Government would have established, that is, generally speaking, the constructing agency's computation, is it not?

General WALL. Generally it is, when we do it, and I am not suggesting that we do this for everyone. I think that a basic philosophy as done through its rulemaking as to FERC, that we would agree to, that they go on their subject of the rulemaking. I think that ought to be considered in that, Mr. Chairman.

The CHAIRMAN. If a dollar is too little, how much is enough?

General WALL. I think that we need something more than a token benefit here. I think that we need whatever is now justified. I don't know how we arrive at that. I would leave that up to FERC.

The CHAIRMAN. I suspect that Commissioner Sheldon is saying, "Thanks a lot."

Ms. SHELDON. You read my mind, Mr. Chairman.

The CHAIRMAN. How would FERC do that? Let General Wall answer that first. Then I will ask you if you agree.

How would FERC do it?

General WALL. I don't know how FERC would do that, Mr. Chairman.

Ms. SHELDON. We have some proposals in our rulemaking and I imagine we will have some answers to this rather soon.

Under your proposal you would set the level. If you would like us to, Mr. Chairman, I think that we could run some figures for you on some projects at varying levels, if this would be of any assistance to you.

The CHAIRMAN. We had suggested, or Congress did this as a matter of policy and was supported by the administration at the time the act was passed, that a utility that was one that was purchasing power from another, or from a new source of electricity, would pay the avoided cost. You make those computations under PURPA. Is that where our problem lies? That computation may yield rates that are higher than are necessary. Therefore, there may be a spread between the investment and the amount that is received.

Ms. SHELDON. The avoided cost does not have anything to do with our devising the annual charges. What we propose is the sharing of the net benefit.

The CHAIRMAN. Sharing the net benefits and not under the avoided cost formula?

Ms. SHELDON. That's right.

The CHAIRMAN. We are not dealing here with the question of how much is too much as compared to avoided cost. I assume that the objections from the Department of the Interior and from the Corps of Engineers is on the basis, because of the variations in cost of production as compared to investment cost, that there is a variation in rewards. Isn't it better, then, if you are going to limit the amount of rewards based upon investment, to limit that to a return on investment rather than operating a bonus bid system in which all the bonus bid does is drive up the cost of this to the consumer?

Mr. CARRUTHERS. Mr. Chairman, why would we ever want to limit the return on investment for any enterprise? I believe that, using the bonus bidding system, the most efficient operator would achieve the right to develop hydroelectric capacity at a Federal dam.

The CHAIRMAN. It depends on what he thinks that he can sell it for. Isn't that right? He is going to make a calculation as to how much that he can get for electricity he is turning out.

Mr. CARRUTHERS. That is going to be part of his calculation. It is a rather strict investment decision on the part of the enterprise.

The CHAIRMAN. But that, in every instance, will drive it up toward the avoided cost, will it not?

Mr. CARRUTHERS. I would assume that would be in their calculations, yes.

The CHAIRMAN. The investor's calculation?

Mr. CARRUTHERS. Yes.

The CHAIRMAN. What could he get for it? He will go to the distribution utility and say, "It'll cost you *x* number of mills to do it some other way. I can give it to you for 10 percent less."

Mr. CARRUTHERS. And that would be reflected in his bonus bid.

The CHAIRMAN. You would guarantee that, in every instance under the bonus bidding, the consumer would pay right up as close as possible to avoided cost.

Mr. CARRUTHERS. It depends more on the royalty rate that you charge than the bonus bid. The bonus bids are not going to be extravagant in many cases, in my view.

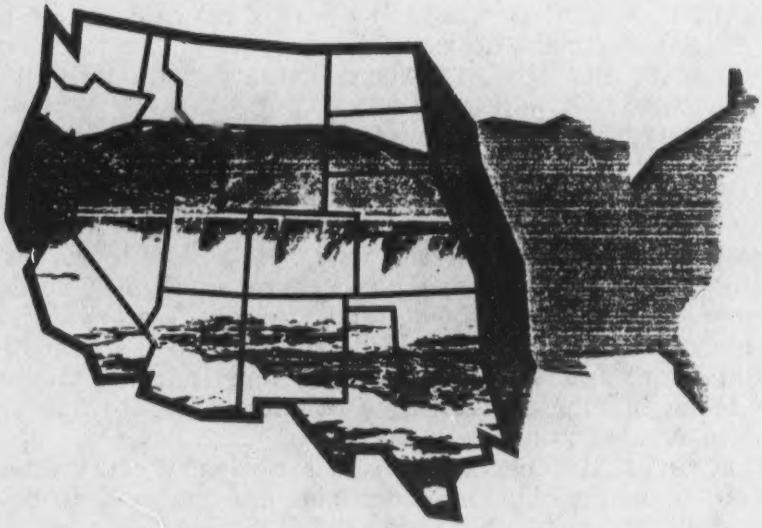
The CHAIRMAN. That's the adjustment, isn't it? Why wouldn't it be?

Mr. CARRUTHERS. Many of the feasible sites have relatively low benefit/cost ratios. In a Bureau of Reclamation study of 57 economically feasible sites, 37 had benefit/cost ratios of less than 1.75. If there were a fixed royalty rate, the bonus bids in these cases would be rather low. The lower the royalty rate, the higher would be the bonus bids. The bonus bids would also tend to be higher on projects with higher benefit/cost ratios.

[Subsequent to the hearing Mr. Carruthers submitted the following:]

REPORT ON ASSESSMENT OF

LOW-HEAD HYDROELECTRIC SITES
IN THE WESTERN STATES



METHODOLOGY AND SUMMARY

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION

TUDOR ENGINEERING COMPANY
DENVER, COLORADO

MARCH, 1982

TABLE VIII-1 ENVIRONMENTAL AND SOCIAL RATINGS ECONOMIC SITES

Sheet 1 of 2

Site Number	Site Name	B/C Ratio	Environmental Rating 1/	Social Rating 1/
CA 2U015	Goodyears Bar	1.14	3	1
CA 2U027	Mill Creek	1.14	3	1
CA 2U028	D'Amico Dam	1.36	2	1
CA 2U029	Hamster Dam	1.29	2	1
CA 2U036	Lamoine	1.23	2	1
CA 2U039	Bethstein	1.70	2	3
CA 2U057	Big Bar	1.98	2	2
CO 5U024	Gore Canyon	1.04	2	0
CO 5U026	Radium	1.34	2	1
CO 5U027	Glenwood Canyon	1.19	2	3
CO 5U028	Storm King	1.97	2	3
CO 5U029	South Canyon	1.47	2	3
CO 5U030	Garfield	1.07	1	3
CO 5U031	Grand Valley	1.51	1	0
CO 5U032	De Beque	1.58	2	1
ID 4U001	Kanaka Rapids	4.44	3	1
ID 4U002	Auger Falls	5.32 ←	2	1
ID 4U006	Porter Creek	1.69	1	1
ID 4U008	Gardena	2.12	1	1
ID 4U009	Dry Buck	2.36	1	1
ID 4U011	Tripod Peak	1.11	1	1
ID 4U024	Lufkin Bottom	2.87	3	1
KS U0093	Edwardsville	1.44	0	1
MT 4U003	Lower Thompson Falls	1.66	0	1
MT 4U004	Tepee	2.15	2	1
MT 4U007	Lombard	1.07	1	0
MT 4U010	Sentinel	1.34	1	0
MT 4U122	Little Porcupine	1.06	1	1
MT 4U125	Ulm	1.05	1	2
MT 4U150	Alberton	1.86	2	1
MT U3012	Weeksville	6.10 ←	2	1
MT U3017	Seven Mile Rapids	3.19	2	1
MT U3020	Cold Creek	2.06	2	1
MT U3022	Superior	3.25	2	1
NM 5U009	Mancos River	1.04	2	1
OR 3U006	Lower Opal City	3.32	2	1
OR 3U007	Upper Opal City	2.92	2	1
OR U0921	Black Canyon	1.06	1	0

TABLE VIII-1 (Continued) Sheet 2 f 2
ENVIRONMENTAL AND SOCIAL RATINGS
ECONOMIC SITES

Site Number	Site Name	B/C Rating	Environmental Rating 1/	Social Rating 1/
TX 5U002	Threemile Creek	1.65	1	0
TX U0028	Garrett's Bluff	1.03	0	3
TX U0039	Valliant Reservoir	1.11	0	0
UT 5U005	Sand Knolls	3.51	3	3
UT 5U016	Mat Martin	2.67	3	1
UT 5U017	Dead Horse	3.50	3	3
UT 5U018	Horse Thief	1.74	3	3
UT 5U033	Ninemile	1.50	3	2
UT U0051	Slickhorn	1.23	3	2
WA 3U007	Pinnacle Peak	2.16	1	2
WA 3U008	Mud Mountain No. 2	2.19	2	1
WA 3U009	New Husum	1.15	3	2
WA 3U023	Brush Creek	1.08	3	1
WA 3U046	New Robe	1.94	3	1
WA U0168	Warnick	1.28	3	2
WA U0614	Oroville	1.67	2	2
WY 8U017	Cody	1.11	2	0
WY 8U018	Trotters Station	1.01	0	0
WY 8U019	Iron Creek	1.01	0	0

1/ Impact Rating Scale:
(0) None, (1) Minor, (2) Moderate, (3) Substantial, (4) Major

The CHAIRMAN. All that you do is capitalize the bonus bid, isn't it?

Mr. CARRUTHERS. There is an element of that, but that is not the only aspect of it.

The CHAIRMAN. You start out with your royalty. You calculate what you can get, what rate of return you want, and you add to your bonus bid right up to that dollar amount. I submit to you that, under that system, the consumer is going to take it in the neck every time, that is, every time it is a good prospect. The only time that the consumer won't take it in the neck is when it is a poor prospect.

Mr. CARRUTHERS. I'm not convinced of that, Mr. Chairman.

The CHAIRMAN. Tell me why it isn't true.

Mr. CARRUTHERS. I think that the bonus bid is not going to be a significant factor. It is a means of selecting who receives the right to develop the site. The key to how much is to be passed on is how you set the royalty rate.

The CHAIRMAN. Let's stop for a moment right at that point. If, as a matter of fact, the bonus bid isn't a significant factor in the overall cost, why isn't the person who is bidding there going to bid right up to the highest possible dollar? Isn't he going to be forced to in the bidding process?

Mr. CARRUTHERS. Simply because not very many people are going to have the opportunity to develop that power site. I don't think that there is a big movement underway that I am aware of going from site to site to look for those development opportunities.

The CHAIRMAN. We have firms of consulting engineers out trying to find municipalities to apply all across the country, dozens of them, hundreds of them.

Mr. CARRUTHERS. But the municipality has to ask to bid, does it not, in the case of a preference site situation? As a consequence, they have a responsibility to the municipality, if they are providing power, to take that under consideration. Isn't that a business strategy to determine how much you have to pass on, or is that a Government responsibility?

The CHAIRMAN. It is a business strategy to find out how much you have to pass on and what you suggest is that would be maximized.

Mr. CARRUTHERS. No; it is to recover for the Federal Government a reasonable return on an investment in the overall project. The royalty rate will do that. We don't intend in any way, shape or form, to take advantage of a monopoly type situation and to drive the price of energy up. There has never been a policy of the Department of the Interior to do that.

The CHAIRMAN. If that is not the policy, I am a little puzzled to know why the policy and your statement seem to be at variance.

Mr. CARRUTHERS. I don't think it is at variance. Very simply, we have an experience and have had this in energy programs for a long time in using this very system. I don't think anybody would argue that we ever extracted a monopoly profit as a result of using this kind of system. We have similar limited resources. In geothermal in California we bid this way. We don't seem to be driving the price of energy up to the degree that you assume.

The CHAIRMAN. How many billions of dollars are in bonus bids?

Mr. Carruthers. In what area? In the Department of the Interior now we make about $12 or $13 billion a year in the energy programs. We are rapidly reaching the point now where the royalty payments are more significant than the bonus bids in that system. I can't give you those numbers off the top of my head. I'd be happy to provide this.

[The information follows:]

7/28/83

Onshore Mineral Receipts ($ millions)
(based on figures in Public Land Statistics)

	1973	1974	1975	1976	c/ 1977	1978	1979	1980	1981	1982
Oil and Gas - total	135.9	189.0	238.8	248.5	307.7	352.0	400.6	613.9	743.1	1070.5
rents and bonuses	36.0	38.0	47.5	42.8	51.4	66.0	60.8	113.3	180.7	363.7 d/
royalties	99.9	151.0	191.3	205.7	256.3	286.0	339.8	500.6	562.4	706.8
Oil Shale - total	-	65.6	65.6	65.6	-	-	-	-	-	129.4 e/
Coal - total	2.8	4.2	5.2	7.3	10.2	11.9	16.4	22.4	41.1	70.9
rents and bonuses	.1	.4	.1	.1	.1	.1	1.0	.4	2.7	5.5
royalties	2.7	3.8	5.1	7.2	10.1	11.8	15.4	22.0	38.4	65.4
Geothermal - total	-	-	13.4 b/	2.6	3.1	3.9	16.5	3.9	4.6	9.7
rents and bonuses			13.4	2.6	3.1	3.9	16.5	3.9	4.6	8.9
royalties			-	-	-	-	-	-	-	.8
Phosphate - total a/	.6	.6	1.6	1.4	1.1	1.9	2.4	2.7	2.2	2.5
Potash - total a/	3.7	4.2	5.6	6.6	5.8	6.3	7.5	10.0	10.6	10.2
Sodium - total a/	2.4	2.8	5.0	6.5	8.5	10.1	11.7	12.1	11.5	8.3
Other - total a/	3.8	5.3	7.9	9.1	8.1	16.2	31.4	17.1	8.9	11.6
rents and bonuses	1.0	1.0	1.1	1.1	1.1	2.3	18.5	16.1	4.9	7.7
royalties	2.8	4.3	6.8	8.0	7.0	13.9	12.9	1.0	4.0	3.9
Total receipts	149.2	271.7	343.1	347.6	344.5	402.3	486.5	682.1	822.0	1313.1

a/ Sodium, phosphate, and potash receipts collected on acquired lands are included in the "other" category, which also reflects collections for other miscellaneous minerals leased under the 1920 Mineral Leasing Act.

b/ Geothermal receipts shown under "Sale of land and material" in Public Lands Statistics.

c/ Transition Period (July 1 - September 30, 1976) total receipts were $71.5 million, including $12.2 million in rents/bonuses and $59.3 million in royalties.

d/ Includes $57.2 million in revenues from acquired military lands (not previously collected and distributed by BLM) and $71.4 million from NPR-A sales. Excludes $107.5 million in simultaneous oil and gas filing fees shown in the 1982 PLS under oil and gas.

e/ Result of settlement of legal oil shale issues in Utah.

The CHAIRMAN. It seems to me what I see happening is that there is a great deal of competition for the best project. Firms and engineers have fanned out across the country looking for projects to sell to municipalities. A lot of actual applications are on file. How many different applications do we have? Do you have any idea?

Ms. Sheldon, have you any idea?

Ms. SHELDON. About 1,000 to 1,500 permits with 300 at Federal dams. It is probably 1,500.

The CHAIRMAN. That seems to be a fairly active market at the present time. It seems to me that is something that indicates that there is some degree of economic competition. Economic competition is a great regulator but the regulator in this instance is how much the consumer can be required to pay. This is unlike an ordinary utility regulation in which the investment is based on historical investment cost. We are talking about a new investment based upon an old one.

Mr. CARRUTHERS. Mr. Chairman, we are trying to do two things. It is to select someone to be on the site. For example, I give you one dam and two institutions are interested on being on the site. Why choose one over the other? I have no idea. We have a long, laborious and expensive process for them to go through to determine which one will be on the site. The economic system works quite well in making that selection from time to time.

The second point is we recover for the Federal Government an appropriate amount to help us to defer the cost of the project, not a monopolistic amount. If we are going to talk about maximizing the return to the Government, that is clearly a different objective than we have at Interior. We just want to cover the cost of Government projects. We don't anticipate making profits, nor have we ever really been in the business of maximum profit in leasing programs.

The CHAIRMAN. I hear what you say and I like what you say. I don't see it being translated into action in this particular instance.

Now, General Wall, on page 4 of your statement, you say that the bill is unclear on what is considered an unreimbursed cost. What do you consider an unreimbursed cost?

General WALL. This is the cost of processing permits, administrative work review, that sort of thing, sir. I think that those are costs that ought to be recovered.

The CHAIRMAN. We're not talking about recovering anything about the Federal investment in the facility itself?

General WALL. We look at it a little bit, well, if I can be allowed to expand just a little.

The CHAIRMAN. Yes.

General WALL. We look at three areas as to our sites we are interested in. If the Federal structure is already existing or already built, then the non-Federal interest would be 100 percent of the cost, would pay 100 percent of the cost of this to construct the powerhouse and the associated things there, and the corps would be reimbursed with, or for, costs that are associated with the review of the FERC application, inspection, and so forth.

In cases where we have already put a penstock in one of our dams and waiting for the power to be developed by somebody, then those costs probably ought to be recovered at that time, too. FERC would charge a reasonable, and I guess that is what we were talking about earlier, a reasonable amount for the use of the Government facility. That is the water behind the head and so forth.

The second area is where the Federal structure is under construction. It is in the way of being constructed, such as the Red River Waterway in Louisiana. There again, we look at the Federal interest that would be expected to pay 100 percent up front of the cost construction of the dam and so forth as allocated to hydropower. The Red River navigation project, as I mentioned, is an example.

What we like to do in those particular cases is that we don't forego the option, that is, so that we don't forego the option where we have construction underway right now, that we be allowed to go out and negotiate and get some people in there early on so that we don't preempt the possibility of having power in there later on, and we would like to get the people interested right now up front for those before we forego the options.

The third area is where we have no Federal facility at a site anyway. It may be a corps site or something else that is not under construction. We would like the local sponsor to pay 100 percent of the cost of construction allocated to hydropower if we built it. The power would go to the Federal power grid and to the marketing associations, and so forth.

This is basically where we are coming from in these areas.

The CHAIRMAN. You're not talking about on an existing project, costs that have not been reimbursed from a specific source.

General WALL. FERC would recover that by a reasonable charge, except in that area that I am talking about where there might have been——

The CHAIRMAN. I didn't think that we were talking about a reasonable charge having anything to do with what the cost was. We are doing this on the basis of what the value is, if I understand this.

General WALL. Whatever the method used, it would be some amount charged for the use of the water head behind it.

The CHAIRMAN. Mr. Carruthers, you indicated that the Government isn't in the business of making a profit. If, in fact, the Government gets back more in royalties or in bonus bids than they invested, aren't they making a profit?

Mr. CARRUTHERS. We might dangerously approach the time where we might actually pay for a water project totally as a result of using that system. As I see it, we have never been able to really recapture all of this.

The CHAIRMAN. But you don't care whether the Government would make some money on it. That would be desirable from your standpoint.

Mr. CARRUTHERS. The rate that we calculated is not a very high rate. The objective of that rate is to recapture the cost of being on the site and get some reasonable return.

The CHAIRMAN. And not the cost embedded in the original project itself?

Mr. CARRUTHERS. If we retrofit a dam, some of the joint costs of that dam ought to be recaptured from the hydroelectric power opportunity.

The **Chairman**. You're making the calculation based on that.

Mr. **Carruthers**. You mean the royalty rate?

The **Chairman**. The royalty or the bonus would be as unrelated to what the cost was of providing the facility?

Mr. **Carruthers**. Yes. In fact, the bidding systems would take into consideration the differences in the opportunity, if that is what you're asking. Some dams are different. Some offer better opportunities than others.

The **Chairman**. I am not talking about opportunities. I am talking about the Federal investment in the original dam.

Mr. **Carruthers**. Yes. We would use 5 percent to recover some of the cost of the Federal dam.

The **Chairman**. Unrelated to the amount of cost.

Mr. **Carruthers**. It would be unrelated to the cost of the dam. It would be retrofitting.

The **Chairman**. It would be related to the cost of the retrofitting.

Mr. **Carruthers**. I don't want you to think that the Federal Government has anything to do with the generators. Those would be put on line by the other enterprise.

The **Chairman**. Go ahead, General.

General **Wall**. The additional storage, I think, that is a related cost. It is the additional storage for water for the head, and that kind of thing.

The **Chairman**. You're talking about changes in operation of the dam.

General **Wall**. Yes.

The **Chairman**. Are you talking about changes in the operation of the dam or are you talking about additional storage capacity? You're not, in this instance, talking about the differences in the operation of the dam in order to maximize power production?

General **Wall**. I am certain if there was flood control on that dam to begin with, this would be getting kind of complicated, for me, anyway, probably not for you. If we have flood control in the dam, then there would be rulemaking curves that we would have to compensate, such as how to release water, and the different circumstances.

The **Chairman**. Ms. Sheldon, do you have any comment at this time?

Ms. **Sheldon**. Mr. Chairman, I think that I would go back now to S. 1132, if I may, on the unreimbursed cost question. We do have agreements between licensees and the Corps of Engineers and the the Bureau of Reclamation. These agreements specify that the licensee will pay some of the construction and the operation costs; also the maintenance costs. I assume these contracts, provide for reimbursement of any designated costs to the U.S. Government. If that assumption is correct, I am not sure what you mean by other additional unreimbursed costs.

I think if you are going to go ahead with S. 1132 that some definition should be made on the unreimbursed cost. I think the Commission may be placed in a position of serving as a third party to contractual agreements between the licensee and another Federal agency. I am not sure that you would wish to place another Federal agency in that position. I think that is something which will have to be defined if we are going to have version of the bill.

The **Chairman**. I appreciate your comment and the actual suggestion made by the General. I was trying to find out whether, from the standpoint of the Corps of Engineers or the Bureau of Reclamation, and we are looking back at original construction costs—that is, we are looking at that amount which is recovered from the various users and whether or not we are going to go back and make a fee for collection of those costs for which there is no direct payment. Apparently, from the answers I have gotten from all three of you, that is not contemplated by any of the three. This is even though the amount of money that is generated by this sale of electricity and by the use of this water, that this might, as a matter of fact, be paid to the Treasury. This is some of the money the taxpayers invested in it. That is not a direct calculation or a direct cost.

I wish to thank all three of you for your testimony. I very much appreciate it. Go ahead, Ms. Sheldon.

Ms. **Sheldon**. If you'll go back to my testimony, Mr. Chairman, I do have another question about the disbursement of funds and annual charges. I do believe in Interior's original testimony, that they had some comment about the Commission disbursing the funds under 17(a) of the Power Act. We do not disburse those funds. We give them to the General Treasury. Treasury disburses them based on the 1921 Comptroller General's opinion, and one following the act of 1938.

I think, you're going to change the Federal Power Act the disbursement question should be also clarified. Hopefully, if you don't do it in the act, you can do it in the legislative history. Right now 50 percent, or whatever the percentage, that Interior should receive for reclamation projects would go to Interior. Whatever the corps is to receive goes to the corps. I am not sure that this is being done equitably at this point.

The **Chairman**. Mr. Carruthers.

Mr. **Carruthers**. Mr. Chairman, I don't know which testimony you're talking about, but we would like to have the act amended to designate that those revenues go to the reclamation fund. We would provide the language to do that if you leave the record open.

[Subsequent to the hearing Mr. Carruthers submitted the following:]

SUGGESTED AMENDMENT TO SENATE BILL S. 1132

To allow annual charges for Bureau of Reclamation sites to be paid into the Reclamation Fund.

On page 2, after line 8, add the following new paragraph:

> "Section 17(a) of the Federal Power Act (16 U.S.C. 810) is amended by modifying the last clause of the second sentence to read as follows: "50 per centum of the charges arising from all other licenses, other than those for the use of Bureau of Reclamation facilities, hereunder is reserved and appropriated as a special fund in the Treasury to be expended under the direction of the Secretary of the Army in the maintenance and operation of dams and other navigation structures owned by the United States or in the construction, maintenance, or operation of headwater or other improvements of navigable waters of the United States; and 50 per centum of all charges whatsoever arising from all licenses hereunder authorizing in any manner the use of Bureau of Reclamation structures and facilities shall be paid into the Reclamation Fund."

This amendment would clarify the Federal Power Act to ensure that part of the money collected by the Federal Energy Regulatory Commission for the so-called "falling water charge" and the use of Reclamation facilities would be deposited in the Reclamation Fund.

Note:

Underlined sections are proposed additions to the Federal Power Act.

The CHAIRMAN. Thank you very much.

General WALL. We'd like to do that, too.

The CHAIRMAN. Perhaps Senator Hecht has some questions at this time.

Senator HECHT. Thank you, Mr. Chairman.

I am glad to have this hearing today because this will has a direct application to a proposed hydro development at the Lahontan Dam in Nevada. It was originally built in 1911 and is ripe for hydroelectric renovation. Both the local water district and private and out-of-State developers are interested in upgrading the hydro facilities of the dam. Neither is willing to go forward, however, until the falling water storage issue is resolved.

Mr. Carruthers, just one question for you. How would a bonus bidding system jibe with the preference clause in section 7(a) of the Federal Power Act? Wouldn't FERC be compelled to award development rights to the qualified preference applicant even if the bonus bid were not as high as the competing nonpreference applicant?

Mr. CARRUTHERS. I understand that there are two kinds of preferences concerned with hydroelectric power generation. One is with the Bureau of Reclamation and one by FERC. I think the one with the Bureau of Reclamation has to do with the preference to the power and the one at FERC deals with the preference to be on the site.

I don't see that the bonus bidding is inconsistent with that at all. In many cases there are more than one type of preference customers on a particular site. If that is the case, they can bid among themselves.

Alternatively, I propose in the Department of Interior that preference customers be given some kind of bonus points to assure that they have the advantage that was assured to them and that some calculation be made where, for every dollar bid by a customer, there is an additional bonus for the preference customer. That would put them all in the market situation. We would still recognize the fact that certain preference customers did have an advantage.

Senator HECHT. Ms. Sheldon.

Ms. SHELDON. Yes, sir.

Senator HECHT. How do you feel about that?

Ms. SHELDON. Well, I would like to ask the Secretary a question. Do you not feel, sir, that the Federal Power Act would have to be amended to change the preference if you were going to use a bonus system?

Mr. CARRUTHERS. That's why I was so excited to come to the Senate today where they change the laws and being in anticipation that they would agree to that change.

Yes; I do recognize that. You can lobby for such a change.

Ms. SHELDON. I think we made that clear. Not only would the preference have to be changed, but also several sections in title I. You would have a major revision.

I really did not come here to talk about royalty and bidding. It is a separate issue entirely. I thought that we were talking today about S. 1132.

The **Chairman.** I almost asked some questions about that subject. You suggest it is a separate issue. You don't want to get into it today?

Ms. **Sheldon.** No; I meant the royalty issue and the bidding issue, they seem to me to be separate from S. 1132, Mr. Chairman.

Mr. **Carruthers.** Senator Hecht, it is my view that we have an excellent opportunity here to really simplify the system and to give some certainty to those people that want to develop hydroelectric power. This is to tell them exactly about the future and to let them manage their own business the way that they want to without a lot of Government regulations and people looking over their shoulders. It is a direct system. It is simple to operate. We have been doing it for years in other areas. It has a lot to lend to it.

The **Chairman.** Where is Commissioner Broadbent?

Mr. **Carruthers.** The Commissioner asked me to represent him at this meeting. He suggested that I might be able to handle it but I can tell from the questions that I should have brought him along.

Senator **Hecht.** He can help us with the Lahontan Dam.

He is very knowledgeable about such matters. I think that he was born in Nevada. Give him my best.

Mr. **Carruthers.** Thank you, Senator.

Senator **Hecht.** Thank you, Mr. Chairman.

The **Chairman.** Thank you, Senator Hecht.

Again, I want to thank each of the witnesses today for helping us out on a problem that needs some resolution.

There will be further questions to the witnesses of this panel and others for responses in writing and we will hold the record open for 2 weeks for responses to those questions.

Ms. **Sheldon.** Thank you.

Mr. **Carruthers.** Thank you.

General **Wall.** Yes, sir.

The **Chairman.** The second panel is next. We have Mr. Logan Lanham, Idaho Power Co., Mr. John W. Baird, secretary of the Quincy-Columbia Basin Irrigation District, Mr. John Boudreau, project manager, Friant Power Authority, and Mr. William H. Patton, assistant city attorney, city of Seattle.

The statement of each witness will be placed in the record in full after the witnesses summarize it or give the statement as they see fit.

Mr. Lanham, you're first. It isn't often that the Chair is able to give a preference to an Idaho constituent. This is one. You may go first.

Your statement will be placed in the record after you summarize it.

STATEMENT OF LOGAN LANHAM, SENIOR VICE PRESIDENT, PUBLIC AFFAIRS, IDAHO POWER CO.

Mr. **Lanham.** Thank you, Mr. Chairman.

For the record, my name is Logan Lanham of Boise, Idaho. I am senior vice president of public affairs for the Idaho Power Co.

I will be brief, Senator, because you are aware of our service area and our company.

I would like to compliment you for sponsoring this legislation. We are here in support of S. 1132, which amends the Federal Power Act, to specify the charges for projects with licenses issued by FERC for the use of Federal dams and other structures.

Our service area is mainly southern Idaho and eastern Oregon and northern Nevada. As you know, we are primarily a hydroelectric system because 70 percent of our energy is generated from flowing water.

We think, and we are optimistic, that we will be able to meet our customers' needs and supply them with the major portion of hydroelectric energy until the 1990's.

In the meantime, of course, we will have constructed some projects in northern Nevada, those under construction at the present time, and also over in Wyoming.

We have 15 hydroelectric projects that generate this power for our customers. One that is in the final stage is the Cascade hydroelectric project generating 12,800 kilowatts on the Cascade Dam and Reservoir, which is operated by the Bureau of Reclamation. This will replace a former 300-kilowatt hydroelectric plant that was constructed by a predecessor company and was in operation many years prior to construction of the Cascade Dam. It is one of the possible seven hydroelectric projects in Idaho that could be affected by the passage of Senate S. 1132.

We also have other projects underway, or at least we are investigating the projects in the service area. The sum is about 500,000 kilowatts of installed capacity.

As you know, we are in the process of transferring the license for the Lucky Peak project from the Boise project board of control in exchange for annual payments. The Lucky Peak project is on a corps dam near Boise.

As you know, the Federal Power Act allows, as a condition of the license, to charge a reasonable annual charge for the use of Government dams for hydroelectric development. Up to now it has been on a case-by-case basis.

The passage of S. 1132 would place a known cap here, and I would like to stress that it is a known cap, upon that annual charge. The annual charge, of course, would consist of two components, a capacity charge and an energy charge. The capacity charge would be $1 per kW and the energy charge would be a half mill per kilowatt hour. It is easy to compute and administer.

The FERC rulemaking 83-13-000 is an example of how difficult and cumbersome that administration of annual charges could be without S. 1132.

As originally stated, the company supports S. 1132 because it is a known quantity. It enables the company to plan accordingly. It is a known quantity to the developer, to the licensee when he is preparing his analysis on the economic feasibility of the project. It is a known quantity of revenue to be paid to the Treasury by the licensee. It is a known quantity in that it provides a reasonable cap on annual charges by FERC. It eliminates the possibility of the double charges for the use of the structure. It provides the Federal Government with a fixed and known annual payment to be collected. It provides for a reasonable annual charge for use of Federal dams and other structures.

Again, it is easy to determine and easy to administer. It is fair and equitable to developers and their consumers. It does not increase the price of electricity to consumers.

In addition to the capacity charge, an energy charge of one-half mill per kilowatt hour of energy produced was included so that in good, high-water years, both the Federal Treasury and the licensee enjoy the benefit of higher revenues.

In the years of lesser water, both would suffer equally.

This approach provides a mixture of two factors, the energy and capacity, that are reasonable and direct ways of determining what actual benefits to power generation are provided by the Government dam.

At the risk of being redundant, the legislation provides a known quantity so that for financing, budgeting, analysis, and the determination of the economic feasibility of the project, the licensee would have an up-front, definable maximum figure to use.

In conclusion, we support the passage of S. 1132. I think this would be beneficial to both the Federal Government, to the Treasury, and to the person who desires to license hydroelectric projects at Government dams. It treats each equitably. It is very easy to implement. It negates the need for the March 31, 1983, rulemaking RM 83-13-000 proposed by the FERC.

The intent of the legislation is to be fair to both the licensee and the Government. It will encourage the actual utilization of renewable resources and encourage development and enable a developer to analyze the economics of the project which may result in production of energy that would otherwise be lost. I would wish to thank the committee and chairman for the opportunity to express my company's views on S. 1132.

[The prepared statement of Mr. Lanham follows:]

TESTIMONY OF LOGAN LANHAM

SENIOR VICE PRESIDENT OF PUBLIC AFFAIRS

IDAHO POWER COMPANY

BEFORE THE UNITED STATES SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

JULY 25, 1983

My name is Logan Lanham of Boise, Idaho. I am Senior Vice President of Public Affairs for the Idaho Power Company.

We appreciate the opportunity to present our position and views on SB. 1132 amending the Federal Power Act to specify the annual charges for projects with licenses issued by the Federal Energy Regulatory Commission (FERC) for the use of federal dams and other structures. We are appearing in support of the passage of SB. 1132.

The Idaho Power Company is an independent and investor-owned utility, founded in 1916, supplying electrical service to more than 260,000 customers in a twenty-thousand-square-mile area of Southern Idaho, Northern Nevada, and Eastern Oregon. A map depicting the Idaho Power Company service area is attached as Exhibit I. Idaho Power Company's customers have been fortunate in the past as the Company has been able to rely heavily on low-cost hydroelectric generation to supply their energy needs. The Company is one of the nation's few utilities with primarily a hydro base having seventy percent of its generation supplied by fifteen generating plants currently operating, and another under construction on the Snake River and its tributaries. The Company's hydro plants, due to above average water, provided seventy-five percent of the record level of power we generated in 1982 with the balance coming primarily from three coal-fired plants in which it shares ownership.

The Idaho Power Company is optimistic it will be able to meet customers' energy needs for the remainder of the 1980's, assuming of course it enjoys median hydroelectric conditions, normal weather, and favorable operating circumstances. The Company has under construction the second unit of the Valmy coal-fired plant in Northern Nevada which, under present forecasts, would be the only thermal unit the Company would add to its system before the turn of the century.

The Company is in the final stage of completing the 12,800-kilowatt (kW) Cascade hydroelectric project on the Payette River. The Cascade Dam and reservoir is operated by the Bureau of Reclamation. The powerhouse will replace a 300-kW hydroelectric plant constructed by a predecessor company which was in operation for many years prior to the construction of the Cascade Dam. It is one of possible seven hydroelectric projects in the state of Idaho that could or would be effected by the passage of SB. 1132.

In addition to the Cascade plant, we are currently engaged in extensive investigation of several potential low head hydro projects in our service area. We have licenses, preliminary permits, or filed for water rights on nine sites with an aggregate installed capacity of nearly 500,000 kW. In addition, the Company has offered the Boise Project Board of Control (comprised of five irrigation districts) a contract for the transferring of its Lucky Peak hydroelectric license to the Idaho Power Company in exchange for annual payments. Lucky Peak is a 87,480-kW project at the existing Army Corps of Engineers' Lucky Peak Dam near Boise, Idaho. We are working also in cooperation with other irrigation and canal companies to develop additional hydroelectric facilities on canal drops throughout our service area.

As you know, the Federal Power Act allows the Commission, as a condition of a license, to charge a reasonable annual charge for the use of government dams for hydroelectric developments. The setting of this charge is now done on a case-by-case basis. The passage of SB. 1132 would place a known cap upon that annual charge. The annual charge would consist of two components: a $1.00 per kW of installed capacity, and a one-half mill per kilowatt hour (kWh) of energy produced. It would be easy to compute and administer. FERC RM 83-13-000 is an example of how difficult and cumbersome the determination and administration of the annual charges could be without SB. 1132.

As I originally stated, the Company supports the passage of SB. 1132 because it is a known quantity and enables the Company to plan accordingly. The annual charge of $1.00 per kW of installed capacity and the one-half mill per kWh of energy produced is a known quantity. It is a known quantity to the developer or licensee when he is preparing his analysis on the economic feasibility of the project. It is a known quantity of revenue to be paid to the Federal Treasury by the licensee. It is a known quantity in that it provides a reasonable cap on annual charges by the FERC and eliminates the possibility of double charges for use of the structure. It provides the federal government with a fixed and known annual payment to be collected from these generating facilities. It provides for a reasonable annual charge for use of federal dams and other structures that is easy to determine and is therefore easy to administer. It is fair and equitable to the developers and their consumers. It does not increase the price of electricity to consumers.

In addition to the capacity charge, an energy charge of one-half mill per kWh of energy produced was included so that in good, high-water years, both the Federal Treasury and the licensee enjoy the benefit of higher revenues. And in the years of lesser water, both would suffer equally. This approach provides a mixture of two factors--energy and capacity--that are reasonable and direct ways of determining what actual benefits to power generation are provided by the government dam.

At the risk of being redundant, the legislation provides a known quantity so that for financing, budgeting, analysis, and the determination of the economic feasibility of the project, the licensee would have an up-front, definable maximum figure to use.

In conclusion, we support the passage of this legislation. We think it would be beneficial to both the federal government (the Treasury) and to the person who desires to license hydroelectric projects at government dams. It treats each equitably. It is very easy to implement. It negates the need for the March 31, 1983 Rulemaking Docket No. RM 83-13-000 proposed by the FERC.

The intent of the legislation is to be fair to both the licensee and the government. It will encourage the utilization of renewable resources. It will encourage development and enable a developer to analyze the economics of the project which may result in production of energy that would otherwise be lost.

I wish to thank the Committee for the opportunity to express the Company's views on SB. 1132.

EXHIBIT I

COUNTIES WITHIN IDAHO POWER'S SERVICE AREA

IDAHO

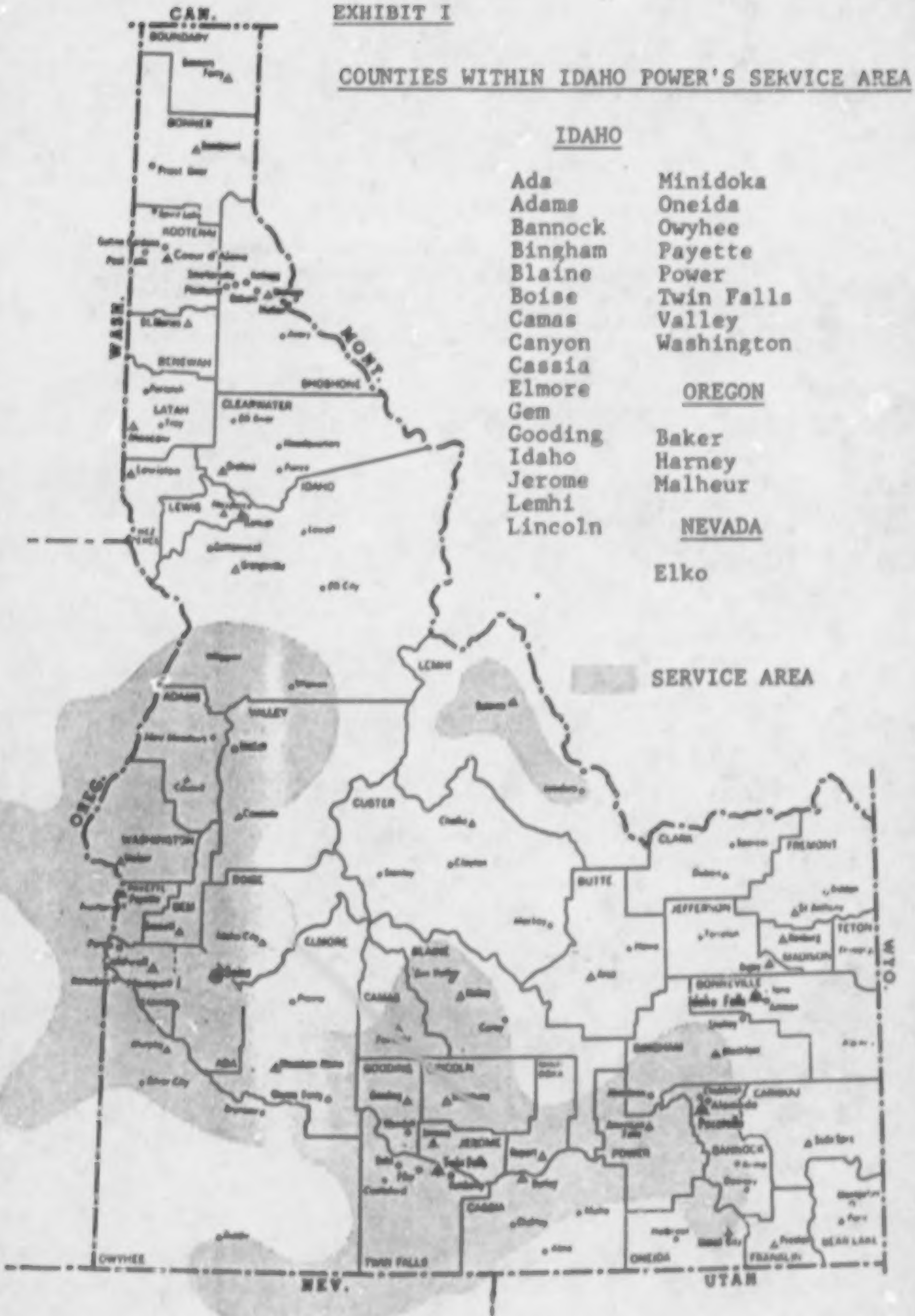
- Ada
- Adams
- Bannock
- Bingham
- Blaine
- Boise
- Camas
- Canyon
- Cassia
- Elmore
- Gem
- Gooding
- Idaho
- Jerome
- Lemhi
- Lincoln
- Minidoka
- Oneida
- Owyhee
- Payette
- Power
- Twin Falls
- Valley
- Washington

OREGON

- Baker
- Harney
- Malheur

NEVADA

- Elko


CAN.
WASH.
MONT.
OREG.
WYO.
NEV.
UTAH
▨ SERVICE AREA

STATEMENT OF JOHN W. BAIRD, SECRETARY-ATTORNEY, QUINCY-COLUMBIA BASIN IRRIGATION DISTRICT

Mr. **Baird**. Mr. Chairman, my name is John Baird. I am the attorney for the Quincy-Columbia Basin Irrigation District, which is one of the three districts of the Columbia Basin project.

While I have been the secretary and attorney for the Quincy District since 1957, my firm has actually represented the Quincy District since 1952. Any expertise that I may have would be primarily in irrigation. This has only been within the last 2 or 3 years that I have become—well, before I go any further, I would like to take about 5 or 10 seconds to express my appreciation to the committee and, in particular, to you, Mr. Chairman, and Senator Jackson. I am not looking for any brownie points particularly here, but this is for your efforts in accomplishing the passage of the Reclamation Reform Act of 1982. It was, I realize, very tough legislation. It was very difficult legislation. I want you to know, at least insofar as the irrigation districts of the Columbia Basin, that the provisions of the act satisfy very nicely the needed flexibility of 95 to 98 percent of our own farmers. At the same time, in my opinion, it preserves the family farm concept.

I, too, wish to be very supportive of S. 1132. I will summarize this very briefly. It provides for only one charge and it settles the jurisdictional dispute between FERC and Interior, and perhaps the corps. It is a simplicity of a determination of the charge which is extremely beneficial for any non-Federal entity which is trying to determine the financial feasibility of a particular project.

I would hope that the charge set forth in the act is not intended as a minimum as well as a maximum. I do believe that the act preserves the discretion of FERC to propose a lesser charge in some situations. There is a difference in the various sites. I do hope that discretion is preserved to FERC.

I would like to pose a philosophical question. I think it should be asked. I am not going to spend much time on it. I don't think that I am going to get very far with it. I think a threshold question should be asked that, in those situations where the United States does not desire to build a small hydro, for instance, 2, 3, 4, 5, or 6 megawatts, and really cannot do it financially or economically as compared to a non-Federal developer. Also, where a non-Federal developer does the construction without cost or expense to the United States, and in view of the attitude of Congress in wishing to encourage development of a small hydro by non-Federal entities, then the issue is whether there would or should be any charge at all. In my opinion, any charge imposed by the Federal Government or by any agency is going to increase the cost somewhat to the consumer. As I said, I am not going to pursue that.

A similar related threshold question is whether or not there should be a difference between the non-Federal entities. There is a difference between non-Federal entities. For example, most irrigation districts are not only paying at least a portion of the construction of the Government dams and facilities in irrigation districts, but they are also paying 100 percent of the annual operation and maintenance costs.

In the case of the project irrigation districts we have an annual charge for operations and maintenance just to keep the system going. This is approximately $10 million per year.

If a third-party non-Federal developer is permitted to come in and build a hydro facility in a situation where the district is paying a portion of the construction and also paying all the O&M, and both elements are needed to make a small hydro go, then it seems to me that perhaps an irrigation district should be entitled to pay a lesser charge than a non-Federal entity which is not paying any of the cost of the construction nor any of the annual O&M for the irrigation system.

I have a proposed amendment that is found on page 8 of my testimony. I am not going to spend too much time on that.

Section 10(e) of the Federal Power Act appears to impose a charge for the use of Government structures and for the development and utilization of power created by any Government dam. To my knowledge, the FERC has never imposed a double charge which perhaps could be imposed under 10(3). I mention it only for the purpose that in two of the licenses that we have received, the charge referred to the use of Government dams and structures. On the third license which we received, the charge referred to the development and the utilization of power created by any Government dam.

I think that, perhaps, in the final drafting that these two could be combined to make sure that there was only one charge intended under 10(e).

I have one other proposed amendment with which I would like to just take a quick moment or two on and to discuss. I have in my left hand here a repayment contract between the United States of America and the Quincy District. They are, or there are identical contracts with the east and south irrigation districts which comprise the Columbia Basin project.

This contract provides that if the districts build a small hydro on these facilities it is entitled to retain all of the revenues, all revenues from such powerplants built by the districts, and from the use, sale or disposal of power and energy therefrom shall be and remain the property of the districts.

We have interpreted that to mean, and we proceeded on that basis, and we have issued now approximately 120 million dollars' worth of revenue bonds.

Part of our procedure in so doing this was based upon the validity of this contract between the United States and the irrigation districts which did not provide, and, in fact, did away with the charge. This contract was negotiated with them for many years between the districts and the United States.

Our first repayment contract in 1945 provided only that the United States could build these incidental powerplants. In 1968 this contact was entered into. We strongly would like to suggest to this committee that perhaps a provision could be inserted in a very short, small amendment which would require FERC and Interior to acknowledge the validity of our article 55(b) insofar as the right of FERC or Interior to impose a site charge.

Basically, Mr. Chairman, we are very much in favor of S. 1132. We think that it answers a lot of questions. We believe it enables non-Federal entities to proceed with the development of small hydro with a sense or knowledge of what they are going to be required to pay and as to the financing and feasibility reports. We support it very strongly. Thank you very much.

[The prepared statement of Mr. Baird follows:]

QUINCY-COLUMBIA BASIN IRRIGATION DISTRICT
TELEPHONE 787-2316 • POST OFFICE BOX 188
QUINCY, WASHINGTON 98848

July 25, 1983

The Honorable James McClure, Chairman,
and Members of the Senate Committee on
Energy and Natural Resources
SD-360, Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator McClure and Members of the Committee:

In re: Testimony of Columbia Basin Project
Irrigation Districts on S.1132

The undersigned is Secretary-Attorney of the Quincy-Columbia Basin Irrigation District and has acted in that capacity since 1957.

The Quincy District is one of the three irrigation districts comprising the Columbia Basin Project, a Federally authorized and constructed reclamation project located in eastern Washington state. The other two districts comprising the Project are the East Columbia Basin Irrigation District and the South Columbia Basin Irrigation District. This testimony with respect to S.1132 is submitted on behalf of all three districts.

Presently, approximately 600,000 acres of lands within the Columbia Basin Project receive irrigation water from Federally constructed irrigation facilities. Upon the eventual completion of the Project, it is anticipated that slightly more than one million acres will be entitled to receive irrigation water.

As a result of the construction of the Project facilities by the United States and the annual operation and maintenance thereof by the irrigation districts, various potential sites exist for the development of small hydroelectric power plants. Presently, the three irrigation districts of the Project, acting in concert, have received seven licenses from the Federal Energy Regulatory Commission for the construction of small hydro power plants. Three of these projects (P.E.C. 22.7, E.B.C. 4.6, and P.E.C. 66.0) have been completed and are now producing power. Three other projects (Summer Falls Project, Main Canal Headworks and the Quincy Chute Project) are now under construction and are scheduled to be on line in 1984 and 1985. Preliminary Permits for six other sites have been secured from FERC and, depending upon feasibility and availability of financing, it is anticipated that licenses for the construction thereof will be applied for within the time permitted by the Preliminary Permits.

Obviously, because of power plants completed, under construction and yet to be constructed, the irrigation districts of the Columbia Basin Project are vitally interested in the provisions of S.1132 and therefore most appreciate this opportunity to appear and testify at this hearing.

A. Arguments In Support of S.1132.

(1) One of the main arguments in support of S.1132 is that it appears to settle the jurisdictional turf battle between FERC and the Department of Interior, as well as other Federal agencies, as to which agency has statutory authority to impose a charge for the utilization of government dams and structures by non-Federal entitites. It also is very beneficial in that it settles the issue of whether more than one agency has concurrent jurisdiction to impose an annual charge for the use of the same facilities. The determination of these issues will be of considerable assistance to all irrigation districts and other non-Federal licensees in their continued efforts to determine the feasibility of a particular hydro project and to secure the necessary financing therefor.

(2) Another advantage of S.1132 is its simplicity in the determination of the annual charge. Again, the capability of ascertaining the amount of the charge in advance of financing is of extreme importance. Frankly speaking, the present uncertainty of the annual charge heretofore determined by FERC, and the threat of an additional charge by Interior, have posed serious problems to non-Federal entities in their determination of the feasibility of a particular project and the financing

thereof. Without going into detail, the proposed rulemaking of FERC relative to the annual site charge for the use of U.S. constructed facilities, the uncertainty of the charge, the difficulty of ascertaining in advance the amount of the annual charge, etc., compounds and magnifies the determination of feasibility and financing of small hydro plants by non-Federal entities. If a charge is to be imposed upon non-Federal entities, the certainty of the charge and the ease of ascertainment is most welcome.

(3) S.1132 further appears to reserve to FERC in proper cases the authority to reduce the maximum annual rental charge set forth in S.1132. This is extremely important inasmuch as the full amount of the maximum charge set forth in S.1132 could serve to render a particular project infeasible. It is well known that the original construction of hydroelectric power plants is extremely capital-intensive but that the annual operation and maintenance costs are considerably less than generating facilities utilizing fossil fuels, nuclear energy, etc. Most certainly, inasmuch as each proposed hydro development has varying degrees of financial feasibility and financing problems, FERC should be encouraged to acknowledge and take into account the fact that the maximum charge mandated by S.1132 could and

should be reduced in those cases where imposition of the full charge would adversely impact financial feasibility and perhaps result in inability to construct a particular project.

B. Advisability Of Any Federal Charge To Non-Federal Entities.

A philosophical question exists as to whether any charge should be authorized by Congress for the use of government dams or structures by non-Federal entities in the construction of small hydro developments. First, it has been the avowed intent of Congress to encourage non-Federal power developments. It does not appear to be economical or expeditious for the Federal government to develop small power plants as compared to development by non-Federal entities. Any government charge obviously increases the cost of a particular project and, in many cases, poses a serious concern as to the financial feasibility thereof. It is therefore suggested that this committee should consider whether it is in the best interests of the United States to impose any charge at all where a small hydroelectric facility is constructed without any cost or expense to the United States.

C. Uniformity Of Charge As To Various Categories Of Non-Federal Licensees.

(1) Assuming that this Committee determines that a charge should be imposed upon non-Federal licensees, the question

arises as to whether the charge imposed should be uniform as to different categories of non-Federal entities.

(2) For example, many irrigation districts are vitally interested in constructing small hydros on irrigation facilities constructed by the United States under Federal reclamation laws. These districts, generally speaking, have entered into repayment contracts whereby a portion of the construction of irrigation facilities is repaid to the United States and, in addition thereto, the districts are obligated to operate and maintain the facilities owned by the United States at their own cost and expense.

(3) The Columbia Basin Project irrigation districts constitute an example of this situation. The Districts are repaying to the United States a portion of the costs of construction and all of the operation and maintenance costs. The annual operation and maintenance costs of the project irrigation districts annually amounts to the approximate sum of $10,000,000. Inasmuch as the development of a small hydro project involves both construction and operation and maintenance, it appears that any charge for the use of government structures should acknowledge the annual cost and expense of an irrigation district as well as the fact that a portion of the construction performed by the United States is being repaid.

(4) If any charge is to be imposed, it is suggested that the charge be made only as to those non-Federal entities which are not obligated to repay to the United States any of the costs of construction nor obligated to pay any of the costs of operation and maintenance of the irrigation system necessary to the operation of a small hydro plant. Presently, FERC does not appear to acknowledge the distinction between various non-Federal licensees. It is therefore suggested that this Committee should consider whether or not it is equitable to impose the same charge upon an irrigation district licensee which is paying a portion of construction and all operation and maintenance costs as compared to a non-Federal developer which is paying neither construction nor annual operation and maintenance costs of the irrigation system.

(5) We suggest that as to irrigation districts repaying to the United States a portion of the construction and paying all of the annual operation and maintenance costs, it would be appropriate for this Committee to consider exempting such districts from any annual charge for the use of government dams or structures.

D. Proposed Clarification of S.1132.

(1) Section 10(2) of the Federal Power Act (16 U.S.C. 803(e)), as presently existing, provides that the Federal Energy

Regulatory Commission (Commission) may impose a charge for the "use of Government dams or other structures owned by the United States". It appears to further provide for a charge for the "development and utilization of power created by any Government dam". It therefore appears that S.1132 could be construed as only impacting the charge imposed by the Commission for the "development and utilization of power created by any Government dam" and leaving intact the authority of the Commission to impose a separate charge for the "use of Government dams or other structures owned by the United States".

(2) We assume that the intent of S.1132 is to assure that only one charge will be made by the Commission for the use of government dams or structures for the production of power by non-Federal entities. While we do not contend that the Commission has heretofore attempted to impose separate charges, we suggest that for clarification S.1132 be modified, as to this point, to include the following underlined language:

> ". . . but in no case shall a license be issued free of charge for the use of Government dams and structures owned by the United States or for the development and utilization of power created by any Government dam. . ."

E. Amendment To S.1132 Proposed By Columbia Basin Project Irrigation Districts

(1) The Districts of the Project have a matter of particular concern to them which they wish to call to the attention

of this Committee for its consideration. It involves the validity of the authority of FERC, in view of the Districts' Repayment Contract with the United States, to impose any charge against the Districts for the use of government structures. A short background of the problem is as follows:

(a) In 1945, the Project irrigation districts entered into a repayment contract with the United States pertaining to the construction of the Columbia Basin Project. The contract was authorized and entered into under various Federal reclamation laws, primarily the Reclamation Act of 1939, 53 Stat. 1187. The 1945 contract between the United States and the Districts did not permit the Districts to construct power developments on Federal irrigation facilities and the United States reserved all rights relative thereto.

(b) In 1968, the United States and the Districts, after several years of negotiations, entered into an extensive 96-page Amendatory Repayment Contract which provided for the transfer of the major portion of the irrigation facilities to the Districts and which contract fully set forth the rights and obligations of the contracting parties. Contemplating the opportunities for future small hydroelectric development, the Districts were successful in negotiating Article 55 of the Repayment Contract which provided substantially that if the United States constructed hydroelectric developments it would retain title and all of the revenues therefrom and further provided that if the Districts constructed such developments, they would retain ownership of the developments and all revenues therefrom. Article 55(b) of the Repayment Contract relative to the rights of the Districts as to power development reads as follows:

> "55(b). With the prior approval of the Secretary, the District either alone or in conjunction with the other districts, may build plants for the production of power and energy and structures and facilities necessary for the operation of such plants and all such plants shall be and remain in the exclusive control, possession, and ownership of the District or districts. All revenue from such powerplants and from the use, sale, or the disposal of power energy therefrom shall be and remain the property of the District or districts." (Underlining added.)

(c) In spite of the foregoing contractual language, the Commission in the issuance of three of the licenses received by the Districts has determined that an annual charge for the use of government-owned facilities would be imposed. The Districts have appealed the imposition of this determination to the Commission, the appeal was denied, and the Districts' Request For Rehearing is presently pending before the Commission.

(2) Obviously, the imposition of an annual charge by FERC reduces the net revenues of the Districts arising from

their power developments. It is the position of the Project irrigation districts that their Repayment Contract is with the United States, that the authority of the Secretary of Interior acting for the United States to enter into such contracts containing the language of Article 55(b) hereinabove quoted is clear and unambiguous, that FERC should acknowledge the validity of the contractual language between the United States and the Districts and that therefore it is improper for the Commission to impose a charge for the use of the Project irrigation structures. FERC has taken the position that it is not bound by the contractual provisions of the Repayment Contract between the United States and the Districts and that it has the authority under 10(e) of the Federal Power Act to impose an annual charge. It is not the intent of the Districts at this Committee hearing to submit a detailed legal brief of its position. However, the Districts have presented to FERC during the administrative appeal proceedings extensive briefs and copies thereof will be made available to the Committee's staff members for review.

(3) It is the position of the Districts that this Committee could at this time properly address the problem of the Districts for the purpose of requiring FERC, an agency of the United States, to honor the contractual commitment made

between the United States and the Project irrigation districts with respect to the imposition of the annual charge for the utilization of irrigation structures of the Columbia Basin Project. Accordingly, the Districts respectfully propose the following amendment (underlined) to S.1132:

> ". . . but in no case, except as hereinafter provided, shall a license be issued free of charge for the development and utilization of power created by any Government dam, and the amount of such annual charge shall not exceed $1 per kilowatt of installed capacity and ½-mill per kilowatt hour of energy produced, and that the amount charged therefor in any license shall be the only charge assessed by any agency of the United States, and shall be such as determined by the Commission, provided that no charge shall be assessed in those cases where the United States has heretofore entered into a contract with a licensee or licensees which provides that the licensee or licensees may build power plants utilizing irrigation facilities constructed by the United States and which contract further provides that such power plants shall be and remain in the exclusive control, possession and ownership of a licensee or licensees and that all revenue from such power plants and from the use, sale, or the disposal of power and energy therefrom shall be and remain the property of the licensee or licensees."

(4) The Districts are not aware of other contracts between irrigation districts and the United States which contain the same contractual commitments with respect to the government charge as is found in the Districts' 1968 Repayment Contract with the United States. Therefore, the suggested amendment impacting only the Columbia Basin Project irrigation districts, while of

significant importance to the Districts, will not substantially impact the financial interests of the United States. In addition, it should be noted that the proposed amendment is not prospective and only impacts contracts "heretofore entered into".

(5) The Columbia Basin Project irrigation districts request that this Committee adopt the proposed amendment hereinabove set forth for the purpose of finalizing the controversy between the Districts and FERC in accordance with the previous contractual commitments between the United States and the Districts.

Respectfully submitted,

QUINCY-, EAST AND SOUTH COLUMBIA
BASIN IRRIGATION DISTRICTS

By: John W. Baird
John W. Baird, Secretary-Attorney
for Quincy-Columbia Basin Irrigation District

STATEMENT OF JOHN BOUDREAU, GENERAL MANAGER, FRIANT POWER AUTHORITY

Mr. **Boudreau**. Thank you, Mr. Chairman.

I would like to summarize my comments. My name is John Boudreau. I am the general manager of the Friant Power Authority. This is a nonprofit organization composed of eight irrigation districts located in the San Jaoquin Valley in California.

At the time that we formed the authority in 1978 we were all experiencing large and escalating energy costs for pumping. We saw the Friant project as a means to overcome these high costs, as well as to respond in a helpful way to the national energy crisis. We then set out to plan and construct the project with tax revenue bonds. There would be no cost to the Federal Government.

To date we have all of the permits and licenses. We have spent over $2 million on development costs. We have even let and since stopped a turbine and generator contract. We were about to let the civil works bids and with construction to start the middle of this month when our power purchaser had declared the project no longer economically feasible. They cited dam use charges which were just then coming into focus as the major concern.

Needless to say, this represents a severe blow to our financial security as a public agency. If S. 1132 is successful, we may still have a project, although it will be delayed 1 year at considerable cost.

At this time, Mr. Chairman, I would like to make some comments regarding the Department of the Interior thinking.

The Friant Dam was constructed without congressional authorization for power. The project's economic merits were established long ago.

I would also like to suggest that the national budget deficits not be overcome by taxing renewable and nonprofit use of, that is, of resources.

In Secretary Carruthers' comments I noted that he had continued to use companies and enterprises. I would like to note that we are a nonprofit agency. We are not trying to make a buck here. What we are trying to do is to overcome large and escalating pumping costs.

I would like to also note that, of the $2 million that has already been spent, there has been several hundred thousand dollars that has gone to the U.S. Bureau of Reclamation.

Thank you, sir. I will submit my full statement at this time for the record.

[The prepared statement of Mr. Boudreau follows:]

FRIANT POWER AUTHORITY

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John E. Boudreau
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MEMBER AGENCIES
Chowchilla Water District
Delano - Earlimart Irrigation District
Lindmore Irrigation District
Lindsay - Strathmore Irrigation District
Madera Irrigation District
Orange Cove Irrigation District
Southern San Joaquin Municipal Utility District
Terra Bella Irrigation District

PRESIDENT
Thomas Cannella
VICE-PRESIDENT
Quentin A. Lindsen
DIRECTORS
C. Myron [illegible]
Harvey S. Crain
Johnny Massaro
Alfred Pistoresi, Jr.
Raymond E. Shick
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ADVISORY COMMITTEE
Robert [illegible]
John E. Boudreau
Donald F. Bird
Samuel C. Fortier
Dale L.R. Lucas
Jack L. McKinney
Robert L. Stanfield
Merry G. Weyia

July 19, 1983

Honorable Members of the Sub-Committee:

Re: Comments of Friant Power Authority
To Sub-Committee on Energy and Natural
Resources on Senate Bill 1132

My name is John Boudreau, I am the General Manager of the Friant Power Authority and I am speaking to you on behalf of that Authority in support of Senate Bill 1132. Friant Power Authority is a joint powers agency which is formed under the laws of the State of California for purposes of permitting eight water districts on the Friant-Kern and Madera Canals to develop a hydroelectric power project at Friant Dam. Our group consists of the following water agencies:

Terra Bella Irrigation District
Southern San Joaquin Municipal Utility District
Orange Cove Irrigation District
Madera Irrigation District
Lindsay-Strathmore Irrigation District
Lindmore Irrigation District
Delano-Earlimart Irrigation District
Chowchilla Water District

Our power project, which was approved by the United States Federal Energy Regulatory Commission (FERC) by license issued September 30, 1982, is designed to permit installation of a 15 megawatt power plant at the Friant-Kern Canal outlet to Friant Dam, an eight megawatt power plant at the Madera Canal outlet of the dam and two megawatt power plants at the river outlet of Friant Dam. From the standpoint of Congressional policy, it indeed carries forth the purposes and goals contained within PURPA in that it permits the development of an environmentally benign energy source, at an existing impoundment facility, to assist in offsetting our country's dependence on fossil fuel fired power plants.

Like many hydroelectric licensees that received its license within the last two years to construct facilities at Federal dams, Friant Power Authority was informed by FERC that the so-called dam use charge, established under Section 10(e) of the Federal Power Act, would be set at such time as FERC promulgated a rule making for the establishment of such a charge. The general consensus seemed to be that FERC's existing "share the benefits" method of computing the charge was unreasonable. Therefore, we had every reason to believe, and had been so informed by FERC's staff, that there was a comprehensive reassessment under way at FERC to establish reasonable criteria for the establishment of an appropriate charge.

After two years of negotiation, we had, as of April 20, 1983, developed a power purchase contract with Pacific Gas and Electric Co. (PG&E) which, apparently, was acceptable to all the parties. However, subsequent to the development of that Agreement, and after the expenditure of over two million dollars in development funds on our project, FERC issued its notice of proposed rule making in which it seeks to not only permanently impose the heretofore unreasonable "share the benefits" methodology, but also to include certain concepts to extract even a higher charge, and one that will be escalated on an annual basis.

While FERC did not specify how the specific charge for our project would be developed, we are informed that it could be $632,000 a year, which fact, obviously, had a tremendous negative impact on the development of our project. At that point in time, we had already accepted bids for the turbine-generators and specifications for the construction of the civil works had been advertised and were due to be open and awarded within three weeks. Nevertheless, after the issuance of the notice of proposed rule making, we were informed by PG&E that due to the dam use charge which could be developed using FERC's new formula, coupled with the impact of declining oil prices, the project was no longer economically feasible and PG&E informed us that they did not wish to pursue the project at this time. There is no doubt in our minds but that if FERC had established a reasonable charge consistent with the concepts contained in Senate Bill 1132, our project would be alive today and in fact, would be under construction at this very moment.

Therefore, I can categorically state to you that because of the apparent insistence of FERC on promulating an exorbitant and unreasonable dam use charge, the very goals this Congress attempted to meet in establishing such programs as PURPA, are being frustrated due to the fact that those who attempt to develop these small hydroelectric projects, are now faced with unreasonable charges which, in and of themselves, make the projects no longer financially feasible. As I am sure you can appreciate, these projects were not of high economic feasibility in the first place. However, they are of sufficient economic attractiveness to encourage development by Districts such as ours, as a means of providing power and/or revenues to offset our own rapidly increasing costs. In addition, the development would be done by our districts in such a manner that there is absolutely no cost to the Federal Government. I am sure you can appreciate, then, how frustrating it is when we have proceeded with such an enormous expenditure of time, money, and resources to develop this project, and then to have FERC seek to deprive these projects of their financial feasibility by extracting an exorbitant charge.

Section 10(e) of the Federal Power Act was never intended to be used as a general revenue raising statute, but rather it is designed to produce a fair charge which recognizes the benefit conferred by the existing Federal facilities. Nevertheless, the raising of general revenues, even at the expense of killing these projects, seems to be the goal of FERC in its latest rule making, and is a goal which is totally inconsistent with developing these power projects.

Accordingly, the Friant Power Authority supports the formula established in Senate Bill 1132. In this regard, we note that the comments of Senator McClure in introducing Senate Bill 1132 attempt to strike a balance between the need to generate revenues for the United States Treasury, and the goal of encouraging the development of these much needed hydroelectric projects. This Bill would insure that a readily determinable, and fixed amount of revenues will be generated for the United States Treasury, and it would also insure that if there are any charges incurred by the Federal Government as a result of the development of these projects, those costs also will be reimbursed.

I might also add that we are supportive of the concept of the Bill in setting up a fixed component, as well as an energy component for reimbursing the United States. In other words, the Federal Government will be reimbursed a certain fixed element for the capacity installed, irrespective of the amount of generation. The second element, one-half mill per kilowatt hour, will accurately track and be based on the amount of generation of the particular site. To the extent a site actually produces greater electric output than had been anticipated, then the Federal Government will receive greater returns on these correspondingly more efficient sites.

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Let me conclude by stating to you that there is no one in our group who seeks to deprive the Federal Government of revenues which properly should be received by it for the development of these projects. We were aware of the provisions of Section 10(e) at the time we undertook our project, and we were fully prepared to pay a reasonable annual charge to the Federal Government for development of the site. However, we do not think an annual charge which in fact frustrates and prohibits the development of these projects is consistent with the Congressional view in originally authoring Section 10(e), nor is it consistent with your recently enunciated policies encouraging the development of these sites. Accordingly, we support the implementation of Senate Bill 1132 as being vitally necessary to encourage development of these projects, and as also being critical in providing to FERC the clear guidelines it needs to establish a fair and reasonable annual charge for these projects.

Thank you for your attention in this important matter.

FRIANT POWER AUTHORITY
By
JOHN BOUDREAU,
General Manager

/sl

STATEMENT OF WILLIAM H. PATTON, ASSISTANT CITY ATTORNEY, CITY OF SEATTLE

Mr. **Patton**. Thank you, Mr. Chairman.

The problem that you bill has generated here, and with the testimony, is one that is common for any governmental agency, including that of the city of Seattle. It is a government entity that has to exist and it has to have a budget. It has to have enough money to go forward. Yet, at the same time, it is set up in order to do things for people.

Your proposed bill is an elegant compromise between those two necessities or the governmental agency. It recognizes the valid claim of the Federal Government for certain payments because a developer of power is using an establishment that was initially funded by the people of the United States. At the same time it is consistent with the national energy policy as set out in the PURPA legislation for development of low head hydro on existing sites. This is, in most cases, an environmentally benign use of those facilities. It also decreases our reliance on nonrenewable energy sources.

The city of Seattle has a direct interest in this bill and on any charge imposed on Federal facilities because Seattle owns its own electric systems. It supplies their approximately 300,000 customers with electricity in the city of Seattle and the immediate areas. It has been in the forefront in the State of Washington in looking at the development of low hydro sites throughout the State. That is, in particular, that we are developing, as purchasers, along with Tacoma, Mr. Chairman. Mr. Baird testified about the projects in the Columbia basin. Any charges imposed on Government Bureau of Reclamation facilities in those areas will be passed on directly to the ratepayers of Seattle and Tacoma.

Seattle is also looking at the development of energy in the Yakima Valley as a single participant without the joint participation of Tacoma.

The possibility of an unknown and significant charge that is also tied to inflation is a significant impediment to looking at the further development of the projects until we know what kind of economics to look at.

When we invest in the Columbia basin irrigation projects we are going to be paying a rate therefore on those projects which is about twice as much as the electricity that we could pay for and buy from the Bonneville Power Administration.

As the Senator indicated in the opening statement, we are trying to take a long-term view of power generation. The city is actively looking for smaller generation sites. We have developed a cogeneration facility with the Metro Plant in Seattle and with a facility with the University of Washington where they heat their buildings in winter. That is a 9 megawatt facility. We are looking for this kind of development, this alternate development, the large; that is, to the large, single station generation.

In Seattle, the residents benefit from the investment that those citizens made in the twenties in the large dam sites when those sites were expensive to invest in immediately. You have to make those long-term projections.

Despite the current surplus situation in the Northwest, we are vitally interested in the development of these sites. We can't really recommend to the city and the citizens and the electric ratepayers that we go ahead with an unknown possible charge that makes those developments uneconomic.

The charge that you set out in S. 1132 is one which can be easily calculated and it varies with the output of these plants, which is a significant factor in the irrigation district facilities because they are often seasonal in the generation of electricity. They are not a constant or a year-round generation.

For example, in the Columbia Basin Irrigation District, that will probably mostly be summer energy production. The rate that the ratepayers of Seattle will have to pay for that will, of course, vary with the amount of energy that is produced under your bill.

The policy that you have set out in this bill not to look at energy production on a short-term basis in the United States; that is, because we can refer to a statement of Mao Tse-tung which is that if you are going to predict, you ought to predict often. Those situations can easily change. We are looking for the long-term investment in those kinds of facilities which you could predict with your bill.

If you look at the water sloshing around these irrigation districts or held behind flood control dams, it is almost criminal not to generate electricity from them.

Seattle appreciates the opportunity the committee has provided us to present our views in support of S. 1132. This bill will enable us to continue the development of new small hydro projects and minimize our reliance on nonrenewable energy resources in furtherance of Federal energy policy.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Patton follows:]

United States Senate
Committee on Energy and National Resources

Hearing on Senate Bill 1132
July 25, 1983

Prepared Testimony of

William H. Patton
Assistant City Attorney
The City of Seattle

On Behalf of
The City of Seattle and
The Seattle City Light Department

The City of Seattle supports Senate Bill 1132. Passage of the bill should be encouraged for the following reasons:

1. The bill validates the Federal Government's claim to a share of the hydro power benefits on federally owned dams without undermining the development of low head hydro generation.
2. The bill retains a fair return to the developers who are assuming the major risks and provides benefits to the Federal Treasury commensurate with its risk.
3. The bill establishes an annual charge that is predictable and that makes energy planning possible.
4. The bill sets a level of charge that continues to promote the use of existing facilities for their hydroelectric potential consistent with the national energy policy to develop small hydro projects and renewable resources for electric generation.

Seattle owns and operates its own municipal electric system which serves the city and immediately contiguous areas. To supply its municipal electric system Seattle owns and operates approximately 1,500 Mw of hydroelectric generation in the state of Washington. The city's own generating capacity meets approximately two-thirds of our current electric needs. Seattle is now adding capacity to four of its hydroelectric facilities and is aggressively searching out and developing low head hydro potential and cogeneration projects. An annual charge for the use of federal dams directly affects Seattle's already significant investment in hydroelectric generation on irrigation district systems in eastern Washington and our potential investment for hydroelectric generation on other federal structures.

While Seattle is not here today to discuss the intricacies of the Federal Energy Regulatory Commission (FERC) rule governing annual charges for the use of federal facilities, we cannot help but contrast it to the proposed bill.

The Senate bill both acknowledges the validity of rental payments on Federal dams, and at the same time allows for realistic planning and promotes use of existing facilities that the Federal Government itself encourages in order to further energy self-reliance. The proposed FERC rule, on the other hand, would greatly impede the development of additional renewable energy resources and force a greater reliance on non-renewable resources such as oil, gas and coal. This is directly contrary to federal energy mandates. Senate Bill 1132 is a fair and predictable alternative to the FERC rule, one which utilities, such as Seattle City Light, can both plan for and accommodate.

Seattle City Light, together with Tacoma City Light, has been in the forefront of developing small hydro projects on Federal irrigation waterways in the state of Washington. In 1980, Seattle and Tacoma entered into an agreement with the South, East and Quincy Columbia Basin Irrigation Districts to purchase the output from six hydroelectric power plants in eastern Washington. We have raised $135 million in the bond market to finance these projects, and expect to finance another $30 million before all the projects are completed. Two of these plants currently are in operation. A third is fully constructed and scheduled to begin commercial operation this year. The three remaining projects are in construction or planning. The last project is expected to begin generating power by the end of 1986. No new roads have been required in the wilderness. Few new transmission right-of-ways are required. Each of the six projects received declarations of non-significant environmental impacts. All of these factors contribute to the economics of hydroelectric development on existing government dams and waterways. A logical and benign use of these facilities is to generate electricity.

The proposed FERC rule would have the opposite effect and discourage hydroelectric development because the government would receive 50% of a project's returns without incurring a commensurate risk. Seattle and Tacoma are paying 100% of the construction and financing costs of these projects, all of the operation and maintenance costs, plus an additional incentive to the irrigation districts. If the FERC rule, or indeed the legislation you are considering here, is adopted, the costs will be passed on to the ratepayers of Seattle and Tacoma. Beyond simply paying for the construction, operation and maintenance of these plants, Seattle and Tacoma have had considerable involvement in the actual construction and operating decisions relating to the plants. We have applied our hydroelectric expertise to every license application, contract award, contractor eligibility determination, bond issue and administrative decision through a power steering committee established by the contract. This arrangement guarantees that the irrigation district water users do not bear additional risks in the development of these plants. Utility costs are similar to what a utility would bear were it to actually own and operate the plants. However, unlike ownership which extends into perpetuity, the Cities' right to the output of these plants is limited to the duration of our 40-year contracts.

Both Seattle and Tacoma as the purchasers and the irrigation districts as the owners are expecting returns on their investments to accrue toward the end of the 40-year contracts. The current cost of electricity from the Columbia Basin Irrigation Districts is twice as high as today's BPA rates. The amount of benefit Seattle and Tacoma will ultimately receive depends upon rates of inflation, escalation and interest costs over the long term. The irrigation districts are also dependent upon these same factors to receive their benefits.

Because it is indexed to inflation, the proposed FERC rule would exceed the proposed returns to any of the three contract parties to the Columbia Basin Irrigation District developments. The FERC rule would provide a 50% return to the Federal government, a 25% return to the irrigation districts, and a 12.5% return each to Seattle and Tacoma. Additionally, the proposed FERC rule would give the Federal Treasury its benefits earlier than either the developers or the districts. The proposed FERC rule would also significantly erode the expected returns of the contract parties after the bonds are retired. A charge indexed to inflation will increase faster than the utility's average system cost upon which the contract benefits are based. In contrast, Senate Bill 1132 would provide the Federal government with benefits equal to one-third of those currently accruing to the irrigation districts during the first 20 years of the contracts.

Without a predictable annual rental charge, additional investment in this kind of development, where the expected benefits accrue only in the later years of the contract, becomes highly problematic. There is considerable expense involved in developing a license application and there is some risk that you may not even receive a license after years of protracted negotiations. Even if one receives a license, uncertainties about the planning of construction and actual construction costs remain. These factors already imperil the profitability of irrigation district projects. Adoption of the proposed FERC rule would reduce their economic predictability even further. Seattle supports Senate Bill 1132 because it recognizes the Federal government's claim to some return for its initial development of existing facilities yet establishes a cost that is predictable and can be factored into our planning process. Seattle also supports quick passage of this bill because we cannot recommend entering into any new contracts based on the ambiguous charge set out in the proposed FERC rule. Unless this bill is passed, or unless FERC radically changes its proposed charge, Seattle will be unable to recommend further development of any small hydro developments using government dams.

Seattle and Tacoma initially invested in the Columbia Basin Irrigation Districts' projects on the basis that the irrigation districts' contracts with the United States give them exclusive rights to any benefits from hydroelectric generation on their facilities. Seattle deeply appreciates the efforts of Senators Jackson and Gorton and Representatives Foley and Morrison in urging the

Department of Interior to honor their contracts with the districts which preclude any annual charge assessment for these specific projects. This issue continues to be unresolved, however. In order to avoid extended litigation with its commensurate costs and uncertainties, Seattle respectfully asks that the Committee consider amending Senate Bill 1132 to clarify the fact that a certain limited number of irrigation district contracts with the United States do not permit a federal annual charge on their facilities.

Seattle appreciates the opportunity the Committee has provided us to present our views in support of Senate Bill 1132. This bill will enable us to continue the development of new small hydro projects and minimize our reliance on non-renewable energy resources in furtherance of federal energy policy.

Thank you.

PSG/HP/DD:cb

The CHAIRMAN. Thank you very much. I want to thank all four of you for your statements and your willingness to appear and testify today on a matter that is of concern.

I would like to just take, as a springboard, the last comment you made, that it is almost criminal not to use the resources. Also, it would seem it is almost criminal to erect barriers to their use which would make it uneconomic to use this.

Now, Mr. Boudreau, you raised the very issue that causes me some concern about the emerging Federal policy, which is the desire to maximize the economic return to the taxpayers of the United States that would render the project uneconomic and leave it not built.

There are so many times that the Federal Government gets involved in situations like this and we end up killing the project or killing the economic return.

You can look at a whole host of evidence on that, such as a blowdown in the national forest in which a lot of timber is blown to the forest floor. It is not harvestable as timber in the ordinary sense of the word. Some people go out and cut some cedar for stakes or fence rails. It has very little economic utility. The minute someone wants to use it, then the Forest Service says that if you want to use it, you have to pay for it. Up until the time that somebody said that they would like to use it, there was no market for it at all. So, then, you start groping for the fee that will render it uneconomic to use. They usually succeed in finding it. It is that kind of thing, it seems to me, to be embedded in the minds of so many people, which is that, somehow, the Government doesn't charge for the use of something that somebody else gets benefit of, an economic benefit of, that the taxpayers have been cheated. This is in the sense that there is an identity between the taxpayers and consumers, a very direct identity. It seems to me to be well served by saying that the ratepayers ought not to be charged two ways. First, it is in their taxes. Second, it is in their rates. It is for something that has already been built.

Here I can make a distinction in my own mind. We have projects that are already built in which there is now an economic value and falling water, and we ought to use it. We ought not to be so concerned about whether or not the Government gets a return on it as it is the fact that resource should be utilized rather than wasted.

If we have learned anything in the recent years, it is that we are not such a rich country that we can afford to do anything. Waste of a resource, it seems to me, ought to be the most highly criminal of all of those acts that we might indeed engage in.

Mr. Lanham, you mentioned a couple of charges that are legitimately attached. One is the capacity charge. There is also an energy charge.

The previous witnesses were talking about the cost of processing and supervising to the extent that they have to supervise construction at a Federal project.

Would you include those Federal, or additional Federal costs, as a legitimate charge against the project?

Mr. LANHAM. Mr. Chairman, when my company looked into the construction of a generating facility at Lucky Peak Dam, which is a corps dam, the corps said to us, that is, sent to us, a 15-page memo of understanding of how the engineering would proceed and how the inspections would proceed. We would pick up charges for that. I have no reason to believe that those charges shouldn't be paid by the developer. They have the habit of occasionally running like a taxi at a red light. They should be reasonable. That is my personal opinion, Mr. Chairman.

The CHAIRMAN. Is there any difference of opinion among the other witnesses at the table on that?

Mr. BAIRD. As far as I am concerned, Mr. Chairman, I don't know what unreimbursed costs refer to in S. 1132.

In just referring to the actual construction of the plant, the administrative costs ought to be incurred by the Bureau or the corps. That is fine. We already do that. If those unreimbursed costs are in the irrigation system, that is, and you take the irrigation district paying anywhere from 50 to 85 percent or 90 percent of the irrigation system, then you attempt to impose those unreimbursed costs as a part of the plant. You might as well forget it, whether it is the irrigation district that is buying it or any other non-Federal entity.

The CHAIRMAN. Mr. Boudreau.

Mr. BOUDREAU. Thank you, Mr. Chairman.

The CHAIRMAN. Go ahead.

Mr. BOUDREAU. I could give you an example or samples of what we consider these types of cost to be because we have paid them to the Bureau. They were for reviewing prints, which is certainly a reasonable request by the Bureau. There were costs for working out the operating and maintenance contract at the Bureau. There was some hydraulic model testing that was required. We paid for that. We now have several hundred thousand dollars, or have committed several hundred thousand dollars to the Bureau. These, we feel, are reasonable costs.

The CHAIRMAN. Mr. Baird.

Mr. BAIRD. I would agree.

The **Chairman**. But you're talking about the additional cost imposed upon the Government as a result of the action of applicant for the additional power facilities.

Mr. **Boudreau**. We have agreed to pay whatever those costs are. This is, such as, we are replacing a certain valve with a necessary design valve. We are paying the extra cost of maintenance on that, anything that is extra due to the actual presence of the power facility.

The **Chairman**. It was suggested, in testimony submitted to us, that there are operation and maintenance costs attached to the operation and maintenance of the project.

Mr. **Boudreau**. Yes.

The **Chairman**. Since a benefit is conferred upon someone now generating electricity, they ought to share in the O&M costs without regard to whether or not the O&M costs have increased as a result of the power facility. Would you agree with that or disagree?

Go ahead, Mr. Baird.

Mr. **Baird**. I would, I believe, agree with that as long as that additional cost did not increase the cost due to the ratepayers or did not make the project infeasible.

In situations where the irrigation districts are paying the cost of O&M, and it does not wish to build a power project itself even though it is paying part of the construction and performing O&M, then, if it does not wish to build a plant that the third party does, I am not too sure in my own mind that the third party should be required to pay to the irrigation district any additional charges.

The **Chairman**. If there are no additional costs, Mr. Baird.

Mr. **Baird**. Yes.

The **Chairman**. Mr. Lanham.

Mr. **Lanham**. This only places a cap on those charges. What is being assumed here is that adding generating facilities to a Government project is a liability.

As an example, and I go back to the Lucky Peak project, at the present time, whenever the corps has to inspect an existing tunnel, they have to shut the water off in its entirety. Consequently, it dries the river up. In the event the tunnel should fail, the spillway runs down the side of a mountain. There is no spillway there.

In all fairness to the developer who develops that project, there should be, in essence, no charge because they are being of benefit to the Government and the people in the area.

The **Chairman**. Are you seeking reimbursement from the Government for that benefit?

Mr. **Lanham**. In all candor, that has crossed my mind, Mr. Chairman.

The **Chairman**. In all candor, I suspect that it has, Mr. Lanham.

Mr. Patton, I'm grateful to you for one addition, I never knew that there was anything in common between Mao Tse-tung and the free market economists. You supplied that link. They say that if you are going to make a forecast, that you ought to make a lot of them. They are mindful of the fact that if you make a lot of them, people might forget the earlier ones.

I appreciate very much the comments that you have made.

We may have some further questions to submit for the record. We would appreciate your response in writing within 2 weeks so that the record may be complete.

Mr. **Boudreau**. Yes, sir.

Mr. **Patton**. Thank you.

Mr. **Baird**. Thank you, Mr. Chairman.

Mr. **Lanham**. Yes, thank you, Mr. Chairman.

The **Chairman**. I might add that, and mention to our friends, that Senator Gorton has asked to be added as a cosponsor to this legislation, recognizing his interest in the State of Washington.

Our next panel consists of Ms. Ann Marie Gibbons, American Public Power Association; Mr. Morgan D. Dubrow, senior staff engineer, National Rural Electric Cooperative Association; Mr. Clarence Grund, Jr., Edison Electric Institute; Mr. John H. Specht, Guadalupe-Blanco River Authority, and Mr. Thomas C. Hough, president of Hough Associated, National Hydropower Association. We also have Granville J. Smith from, or chairman of, the board, Energenics. This is our third panel.

The prepared statements of each of you will be placed in the record in full after you present them. I will invite you to proceed on whichever basis you are most comfortable with in summarizing and delivering those statements.

We will start on the right with Ms. Anne Marie Gibbons.

STATEMENT OF ANNE MARIE GIBBONS, LEGISLATIVE REPRESENTATIVE, AMERICAN PUBLIC POWER ASSOCIATION

Ms. **Gibbons**. Thank you, Mr. Chairman.

I'm Anne Marie Gibbons. I'm legislative representative for the American Public Power Association. I will summarize my statement.

We represent over 1,700 municipally owned and public or publicly owned electric systems throughout the country. Our membership has actively supported S. 1132 and we have sought sponsorship for the bill. We would like to thank the sponsors for sponsoring the bill.

You heard one of our member systems today, Seattle, testify in support of this. We fully agree with the statements of Seattle.

There is immediate need right now for the bill, for S. 1132, because of the proposed rule that the Federal Energy Regulatory Commission has proposed with respect to the annual charges. We feel that the proposed rule will discourage hydro development.

One of our most serious concerns in the proposed rule is that it discriminates against public power systems. It does this by considering the tax status of public power systems and low-cost financing. It does not consider the tax credits available to private companies.

As I said, the APPA members, we have many members who would like to develop hydropower at Federal dams.

I'd like to quote from some of these members to show you how important this bill is to them.

The city of Tacoma said that the method is "very predictable, understandable, and establishes a reasonable level of compensation without discouraging future development, and has wide support throughout the electric utility industry."

In New Mexico, the city of Farmington said that "the city feels it should pay a reasonable annual charge which is equitable, specific and easy to apply, such as that proposed in bill S. 1132."

In Arkansas, the North Little Rock Electric Department, said, "Passage of S. 1132 and the subsequent establishment of a fair and reasonable limit on the annual fees to be assessed on the project could be vital in helping to insure that it remains economically feasible."

There are several reasons why our members are enthusiastic about S. 1132. One is that, first, it does not discriminate against public power systems. Second, it is fair and it is equitable. It pegs the charge to the characteristics of the project, that is, to the capacity and to the actual amount of energy produced. Third, it is easy to apply. Our systems would not need consultants or economists to determine what the charge would be. They could tell immediately up front how much this would affect the economic feasibility of the project. Fourth is because of its certainty. It would have a positive effect on hydro development. Fifth is that it is consistent with the national energy policy. It encourages the hydro development. This is as expressed by the Congress and this committee.

There is one other issue that has been mentioned here about whether the bill would lessen the amount that would be returned to the Treasury. We calculated that, on average, it would be more than the amount that is currently returned under the sharing method that is employed, that was, prior to 1979.

In calculating the amount, the average came to $1.92 per kilowatt of capacity. If you calculate it, those projects that are under S. 1132, that amount would come to $3 per kilowatt.

Another reason is that this would increase the amount returned to the Government. It would encourage hydro development. There would be more projects. There would be more individual charges. The level would be kept at a high level.

In conclusion, Mr. Chairman, we urge this committee to report this bill as quickly as possible.

Thank you, Mr. Chairman. I submit my statement.

[The prepared statement of Ms. Gibbons follows:]

Statement
of
Anne Marie Gibbons, Legislative Representative
AMERICAN PUBLIC POWER ASSOCIATION
in support of
S. 1132, ANNUAL CHARGE LEGISLATION
before the
Senate Committee on Energy and Natural Resources

July 25, 1983

My name is Anne Marie Gibbons. I am Legislative Representative for the American Public Power Association (APPA). APPA represents more than 1,750 local publicly owned electric systems throughout the United States. Our membership has actively supported and sought sponsorship for S. 1132, legislation which would specify that the annual charge for the use of a federal dam cannot exceed $1 per kilowatt of installed capacity and 1/2 mill per kilowatt-hour of energy produced.

We would like to thank Senator James A. McClure, Senator Henry M. Jackson, and Senator Frank H. Murkowski for sponsoring S. 1132 and the Committee on Energy and Natural Resources for holding hearings on this important piece of legislation. We appreciate the opportunity to testify in support of S. 1132.

APPA members have consistently encouraged, and been involved in, the development of hydroelectric resources. Currently, there are approximately 400 sites at government dams, with capacity potential of 13,500 megawatts and an energy production potential for 25 billion kilowatt-hours annually or the equivalent of over 40 million barrels of oil each year. It is in the nation's interest to develop these sites.

The immediate need for passage of S. 1132 was precipitated by a proposed rule issued by the Federal Energy Regulatory Commission (FERC) in March on annual charges for the use of government dams. Rather than encourage development of hydro resources at government dams, the proposed rule will discourage hydroelectric development because of the complexity of the formulas, the unequal treatment of some costs and benefits, and the imposition in most cases of excessive annual charges which will not reflect the actual benefit to the licensee. The proposed rule would use the "sharing of the net benefits" method to determine the annual charge. Net benefits are the difference between (1) the value of the power produced at the project (equal to the cost of producing equivalent power with the least costly alternative sources) and (2) the estimated costs of producing project power. Half of the net benefit would be the amount assessed for the annual charge.

Under Section 10(e) of the Federal Power Act, the Federal Energy Regulatory Commission is authorized to assess an annual charge for hydroelectric power projects that use government dams. The charge mandated by 10(e) must "recompense" the government for the use of the facility, must be "reasonable," and must "avoid increasing the price to the consumers of power...."

S. 1132 fulfills the criteria established by the Federal Power Act. It would set a charge that is reasonable, recompenses the government, and does not unreasonably increase the price of power to consumers.

By specifying that the annual charge for the use of a federal dam cannot exceed $1 per kilowatt of installed capacity and 1/2 mill per kilowatt-hour of energy produced, the bill pegs the charge to the specific characteristics of a project and the charge is proportioned to the value conferred by the federal dam. This charge, coupled with reimbursement to the government of actual operation and maintenance cost for the use of the federal facility, is the most equitable. It sets the charge at the specific capacity of the project and the actual energy produced.

The method specified in S. 1132 is also the most easily applied method of assessing annual charges. It does not demand a host of consultants and economists to determine what the annual charge will be. It allows the developers to determine immediately what the annual charge will be and how it will affect the economic feasibility of the project.

Opponents of S. 1132 may argue that the flat rate approach will not return enough money to the government. Actually, on average, it will return more to FERC than the "sharing of the net benefits" approach used prior to 1979. Since 1979, FERC has, in some cases, set a cap on the amount which will be charged based on the "sharing of the net benefits" approach. The average annual charge assessed by FERC prior to 1979 for the use of government dams was approximately $1.92 per kilowatt of installed capacity. Under the flat rate method of S. 1132, the charge would average out for those same projects to about $3.00 per kilowatt of capacity.

In addition, the formula contained in S. 1132, due to its simplicity and certainty, will have a positive effect on hydropower development. By encouraging greater utilization of existing federal sites, more money may be collected and returned to the Treasury. On the other hand, the method proposed by FERC in its recent rulemaking proceeding will discourage hydro development and result in less money collected through annual charges.

Furthermore, S. 1132 is consistent with the national energy policy to encourage hydroelectric development as expressed by Congress and this committee. For example, under Title II of the Public Utility Regulatory Policies Act (PURPA) of 1978 (P.L. 95-617), which is part of the National Energy Act, a guaranteed market for producers of hydropower from small projects was established. Title IV of PURPA provided a loan program for small scale hydro projects. The Energy Security Act (P.L. 96-294), Section 408, further expanded simplified licensing requirements, extended authorization for the hydro loan program, and authorized a study of existing policies relating to hydro. In addition, the Crude Oil Windfall Profits Act of 1980 (P.L. 96-223), Section 242, established strong incentives to hydro development by providing an 11 percent investment tax credit, in addition to the regular 10 percent investment tax credit, for private hydro development.

Undisputedly, Congress has established a strong national commitment to hydro development, and S. 1132 follows this national commitment.

APPA Membership Support for S. 1132

Many of APPA's members are attempting to develop hydropower plants at federal dams. Quotes from some of these systems will illustrate how important S. 1132 is to their ability to develop these resources economically.

In comments submitted to FERC on the proposed rule, the Seattle City Light Department said the proposed rule "will adversely impact the cost of hydroelectric projects currently under development by Seattle in conjunction with the Light Division of the City of Tacoma and of another project for which a contract is being negotiated. Higher costs to our customers for existing facilities would result." Seattle recommended that FERC adopt the method of S. 1132.

The City of Tacoma said the method used in S. 1132 "is very predictable, understandable, establishes a reasonable level of compensation without discouraging future development, and has wide support throughout the electric utility industry." In contrast, the proposed rule would adversely affect two hydro projects Tacoma would like to develop:

> "Tacoma currently has preliminary permits to develop two hydroelectric projects using federal facilities (Mud Mountain and Howard Hanson Dams) that will be affected by the amended regulation. The proposed methodology for determination of annual charges will result in such high fees that these projects will in all likelihood not be economically feasible. The proposed rule imposes an unreasonable

burden on ratepayers and discourages development of an important renewable resource."

The City of Farmington, New Mexico, in requesting support for S. 1132, said the bill "can have a significant impact on future financial obligations for the City of Farmington and citizens of San Juan County." Farmington said the bill would provide a reasonable annual charge for a project at Navajo Dam:

> "The City of Farmington will shortly be submitting to FERC an application for license to construct and operate a hydro electric project at Navajo Dam. S. 1132 would specify the annual charges assessed for the operation of hydro electric projects at a Federal dam such as Navajo Dam. The City feels it should pay a reasonable annual charge which is equitable, specific and easy to apply such as that proposed in Bill S. 1132."

North Little Rock Electric Department, Arkansas, has submitted an application for a license to build a hydro facility at the Murray Lock and Dam in Arkansas. In a letter submitting a statement supporting S. 1132, the municipal utility's general manager said the passage of S. 1132 and "the subsequent establishment of a fair and reasonable limit on the annual fees to be assessed our project could be vital in helping to ensure that it remains economically feasible." S. 1132 "works out to be on a per KWH basis nearly equal to the net income per KWH received by SWPA for each KWH distributed in 1982."

The Public Utilities Board in Brownsville, Texas, supports S. 1132, saying "this legislation will maintain hydroelectric energy costs from existing dams at reasonable and just rates."

The Borough of Grove City, Pennsylvania, has applied for a license to construct a hydro plant on the Army Corps of Engineers dam on the Sehnango River. In asking for support of S. 1132, the Borough said it would "ensure a fair fee schedule for use of Federal property by power developers. If the fee schedule proposed by FERC is implemented, it will destroy the financial feasibility of our project."

In supporting S. 1132, the Missouri Joint Municipal Electric Utility Commission said "it would eliminate any confusion as to how the costs would be determined; and the charges that are involved also appear to be reasonable both to the Federal Government and to the party owning and operating the hydro equipment."

These quotes are only a sampling of the positive impact APPA members feel S. 1132 will have on hydro development.

FERC Proposed Rule

As mentioned previously, S. 1132 is particularly needed now because of the proposed rule issued by the Federal Energy Regulatory Commission on annual charges for the use of government dams. Prior to 1979, the Commission determined annual charges on a case-by-case basis using the "sharing of the net benefits" method.

Since 1979, the Commission has been expected to change its "sharing of the net benefits" method for calculating the annual charge. The Commission has deferred its determination of annual charges pending adoption of a new annual charge rule. During this period, FERC has not treated all licensees at federal dams in a uniform fashion. For example, in issuing licenses, the Commission has (1) stated that the annual charge eventually assessed will not exceed a fixed dollar amount; (2) specified no maximum annual charge; (3) required the licensee to maintain a reserve fund sufficient to meet its potential liability for accumulated annual charges; or (4) imposed no such reserve requirement.

In 1980, the membership of the American Public Power Association adopted a resolution opposing the "sharing of the net benefits" method. (A copy of the resolution is attached.)

The final "Resolve" clause states:

> NOW, THEREFORE, BE IT RESOLVED: that the American Public Power Association opposes the "sharing of the net benefits" method of computing charges for a non-Federal entity to use a Federal dam to generate hydroelectric power and urges the Federal Energy Regulatory Commission to adopt a nominal fee so as to encourage the rapid and full development of all potential hydroelectric capacity at Federal dams."

The proposed rulemaking continues the use of the "sharing of the net benefits" method. However, rather than a case-by-case approach, the benefit would be computed by a generic formula, using estimates of the least costly alternative source of power and averages to measure capacity for the hydroelectric project. Estimates of the least costly alternatives would be based on regional power value data to be published annually. The proposed rule does not identify the approximately 18-20 geographic regions to be used, nor provide actual power value data for any region.

APPA submitted comments to FERC July 15, opposing the method proposed by the Commission for assessing annual charges for the use of government dams. (A copy of APPA's comments is attached to this statement.) The proposed rule discriminates against public power systems' development of hydroelectric power. While the rule would recognize the tax-exempt status and lower financing costs of public power systems, it would not recognize the tax credits available to private developers in developing both the least costly alternative and the hydro project. The effect of this is that the net benefit and the resultant annual charge for the private company will be calculated at a far lower rate than the true economic benefit derived by the company through tax credits. Thus, in some cases, the annual charge for a private company will be much lower than the annual charge for a public power system. If the tax-exempt status of one entity is recognized in calculating net benefits, then, in fairness, the tax advantages of another should be recognized. This discrimination in treating a public power system differently from a private power system runs counter to the development incentives provided by the preference clause in the Federal Power Act to public power systems since the proposed rule offers little encouragement to public power systems to develop hydro projects.

Second, because the tax costs of private companies will be considered, but not the tax credits, there will be a tremendous difference between public and private companies' net benefits and annual charges. This ludicrous difference in determining net benefits was illustrated in the City of Vanceburg v. Federal Energy Regulatory Commission, 571 F. 2d 630, 643 (D.C. Cir. 1977). The net benefits FERC determined for two hydro projects built by the City of Vanceburg were $487,400 and $455,800, while the net benefits for a private power company using the same facility would only amount to $70,100 and $80,800.

Such discrimination in disregarding the tax advantages available to private developers means a tremendous dollar difference in the amount the Commission determines a public power system will pay in annual charges in relation to the amount a private power system will pay.

Because of this, the proposed rule is contrary to the intent of the preference clause in the Federal Power Act, which gives preference in licensing to public entities for the development of hydro. Allowing such excessive and disparate charges for public systems in comparison with private systems discourages public preference entities from hydro development. We urge this committee to rectify this situation by approving S. 1132 as quickly as possible.

APPA's specific objections to the proposed rule are attached to this statement. In summary, in addition to public power discrimination, our objections include the fact that, in most cases, the net benefits will be overestimated, which will result in excessive annual charges, thus discouraging development. Overestimation will occur because of the use of an estimated average regional power value, the averaging of capacity for a hydro project, disallowing some environmental expenditures as part of the hydro project costs, and not recognizing credits for payments to the Bureau of Reclamation. In determining the least cost alternative, fuel prices would be escalated, and the annual charge would be adjusted yearly according to the GNP Deflator. The result would be a double indexing, amounting to an inflated annual charge.

In addition, the formulas used are unnecessarily complicated, which will make it difficult to determine annual charges, leading to uncertainty, and further discouraging hydro development.

Inappropriateness of "Sharing of the Net Benefits" Method

Whether the "sharing of the net benefits" method for determining the annual charge is generic or case by case, it is not accurate. There are too many assumptions and estimates that have to be made over a 50-year period to result in an accurate determination of net benefits from the project.

For example, a public power system over a 50-year period will negotiate many power contracts and may refinance the bonds used to build the project. "Sharing of the net benefits" method cannot possibly track all these details over a 50-year period.

Second, "sharing of the net benefits" method does not reflect the true economic benefit to the developers. As discussed previously, the "sharing of the net benefits" method, which takes into account the tax-exempt status of public power systems, while not recognizing tax credits available to private companies, results in a tremendous dollar difference between the economic benefits the Commission determines to accrue to public power systems and what it determines will accrue to private power systems. Such a method does not accurately account for benefits.

Third, "sharing of the net benefits" approach bears no relation to the cost to the government for allowing a nonfederal entity to develop hydroelectric power, and it will result in payment to the government in excess of any cost the government incurred in building the dam. Development of a federal dam is subject to congressional authorization. The costs of construction and operation have to be justified on a cost-benefit ratio before a dam is authorized. The project has to be beneficial to the government without consideration of future nonfederal development at the site. Nonfederal development at the federal dam does not in any way detract from the benefits already obtained by the government. The annual charge in this situation represents only the added revenues for the government and not repayment of cost. The hydropower licensee is merely making additional improvements at no cost to the government; the licensee is paying for all costs in addition to the annual charge.

Fourth, "sharing of the net benefits" is not reasonable nor is it consistent with the Federal Power Act. Under Section 10(e) of the Federal Power Act, a licensee is required to pay a reasonable annual charge. It does not appear to be a reasonable charge when there is a more than $200,000 difference in the amount a public system would pay in annual charges as illustrated in Vanceburg and the amount a private power company would pay in annual charges for the same project.

It would appear that the "sharing of the net benefits" method results in general revenue raising when it exceeds and bears no relationship to the federal government's cost for allowing a nonfederal entity to develop hydroelectricity. As interpreted by the court in Vanceburg, Section 10(e) was not intended to be a general revenue raising scheme.

In Vanceburg, although the court agreed that "sharing of the net benefits" was a valid approach to setting the annual charge, it was discussing the method on a case-by-case basis where the licensee is charged in proportion to the benefit "it actually receives." This is not the case in the proposed generic regional approach, which will use estimates and averages. Benefits under the proposed rule are not actually received, but only estimated.

In addition, the court was giving great deference to the "expert judgment" of the Commission. It did say "sharing of the net benefits" approach was not the only method to calculate the charge. The court said, in fixing such charges, the Commission has to consider balancing "all the relevant factors, including the impact of charges on consumer costs, the compensation of the Government, and the course of power development."

Applying that balancing test to the "sharing of the net benefits" approach shows it will have a negative effect on power development, it will overcompensate the government in most cases, and it will increase consumer costs, especially consumers of public power systems which operate on a nonprofit basis and must pass on the cost of annual charges to their consumers. On the other hand, when the balancing test is applied to S. 1132, there is a positive effect. Thus, we urge this committee to move S. 1132 quickly.

Conclusion

In conclusion, APPA fully supports S. 1132. It is fair, equitable, easy to apply, and it would assess a charge specific to the characteristics of each project depending on the amount of capacity and the amount of energy produced. This approach is consistent with our national commitment to encourage hydropower development. S. 1132 is also consistent with the mandates of the Federal Power Act. It would produce a charge which is "reasonable, which recompenses the government for the use of the facility, which does not increase consumers' costs, and which does not discriminate against public power systems. We urge this committee to act on S. 1132 as quickly as possible in order to alleviate any harm which may result from the adoption of the proposed rule FERC would use to assess annual charges on a "sharing of the net benefits" approach.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of:	)	
	)	
Annual Charges for Use of Government Dams and Other Structures under Part I of the Federal Power Act	))))	Docket No. RM83-13-000

COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION

The American Public Power Association (APPA) is the national service organization representing over 1,750 local public power systems throughout the country. These comments are submitted in response to the Notice of Proposed Rulemaking issued by the Federal Energy Regulatory Commission (FERC or Commission) March 31, 1983, Docket No. RM83-13-000, on annual charges for the use of government dams.

I. Introduction

Under Section 10(e) of the Federal Power Act, the Federal Energy Regulatory Commission is authorized to assess a "reasonable annual charge" for hydroelectric power projects that use government dams. Currently, the Commission determines these annual charges on a case-by-case basis using the "sharing of the net benefits" method. Net benefits are the difference between (1) the value of the power produced at the project (equal to the cost of producing equivalent power with the least costly alternative sources) and (2) the estimated costs of producing project power. As an annual charge, the Commission has assessed the licensee 50 percent of this net benefit.

Since 1979, the Commission has been expected to change its "sharing of the net benefits" method for calculating the annual charge. The Commission has deferred its determination of annual charges pending adoption of a new annual charge rule. During this period, FERC has not treated all licensees at federal dams in a uniform fashion. For example, in issuing licenses, the Commission has (1) stated that the annual charge eventually assessed will not exceed a fixed dollar amount; (2) specified no maximum annual charge; (3) required the licensee to maintain a reserve fund sufficient to meet its potential liability for accumulated annual charges; or (4) imposed no such reserve requirement.

A. Summary of FERC's Proposed Rulemaking

The proposed rulemaking continues the use of the "sharing of the net benefits" method. However, rather than a case-by-case approach, the benefit would be computed by a generic formula, using estimates of the least costly alternative source of power and averages to measure capacity for the hydroelectric project. Estimates of the least costly alternatives would be based on regional power value data to be published annually. The proposed rule does not identify the approximately 18-20 geographic regions to be used, nor provide actual power value data for any region.

The Commission's proposed rule will affect a significant number of hydroelectric sites at government dams. Currently, there are approximately 400 available sites at government dams with capacity potential of 13,500 megawatts and an energy production potential for 25 billion kilowatt-hours annually or the equivalent of over 40 million barrels of oil each year. Rather than encourage development at these sites, the proposed rule will discourage hydroelectric development because of the complexity of the formulas, the unequal treatment of some costs and benefits, and the imposition in most cases of excessive annual charges which do not reflect the actual benefit to the licensee.

B. APPA's Comments

APPA is opposed to the method proposed by the Commission for assessing annual charges for the use of government dams. The proposed rule discriminates against public power systems' development of hydroelectric power. While the rule would recognize the tax-exempt status and lower financing costs of public power systems, it would not recognize the tax credits available to private developers in developing both the least costly alternative and the hydro project. The effect of this is that the net benefit and the resultant annual charge for the private company will be calculated at a far lower rate than the true economic benefit derived by the company through tax credits. Thus, in some cases, the annual charge for a private company will be much lower than the annual charge for a public power system. If the tax-exempt status of one entity is recognized in calculating net benefits, then, in fairness, the tax advantages of another should be recognized. This discrimination in treating a public power system differently from a private power system runs counter to the development incentives provided by the preference clause in the Federal Power Act to public power systems since the proposed rule offers little encouragement to public power systems to develop hydro projects.

In addition to being contrary to the Federal Power Act, the proposed rule is also contrary to the national energy policy developed by Congress in the Public Utility Regulatory Policies Act (PURPA), the Energy Security Act, and the Crude Oil Windfall Profits Act.

A major problem with the proposed rule is that, in most cases, the net benefits will be overestimated, which will result in excessive annual charges, thus discouraging development. Overestimation will occur because of the use of an estimated average regional power value, the averaging of capacity for a hydro project, disallowing some environmental expenditures as part of the hydro project costs, and not recognizing credits for payments to the Bureau of Reclamation. In determining the least cost alternative, fuel prices would be escalated, and the annual charge would be adjusted yearly according to the GNP Deflator. The result would be a double indexing, amounting to an inflated annual charge.

In addition, the formulas used are unnecessarily complicated, which will make it difficult to determine annual charges, leading to uncertainty, and further discouraging hydro development.

APPA's comments will discuss: (1) the rule's discrimination against public power systems; (2) national energy policy; (3) the inappropriateness of using "sharing of the net benefits" approach; (4) the proposed rule's method for determining the cost of the hydroelectric project to the licensee; (5) the proposed rule's method for determining power value; (6) the application of the proposed rule; (7) an alternative approach of using a flat rate annual charge not to exceed $1 per kilowatt of installed capacity and 1/2 mill per kilowatt-hour of energy produced.

II. Discrimination Against Public Power Systems

The proposed rule discriminates against public power systems' developing hydro. In determining power value and hydro project cost, the rule considers the tax-exempt status and lower financing costs of public power systems, while it does not consider the tax credits available to private developers in developing both the least costly alternative and the hydro project. This discrimination against public power systems results in a ludicrous difference in determining net benefits. As illustrated in the City of Vanceburg v. Federal Energy Regulatory Commission, 571 F. 2d 630, 643 (D.C. Cir. 1977), the net benefits FERC determined for two hydro projects built by the City of Vanceburg were $487,400 and $455,800, while the net benefits for a private power company using the same facility would only amount to $70,100 and $80,800. This tremendous difference between public and private companies' net benefits resulted because the tax cost, but not the tax credits, were included in calculating net benefits. Such discrimination in disregarding the tax advantages available to private developers means a tremendous dollar difference in the amount the Commission determines a public power system will pay in annual charges in relation to the amount a private power system will pay.

Because of this, the proposed rule is contrary to the intent of the preference clause in the Federal Power Act, which gives preference in licensing to public entities for the development of hydro. Allowing such excessive and disparate charges for public systems in comparison with private systems discourages public preference entities from hydro development. This runs directly counter to the development incentives provided by the preference clause to public power systems.

III. National Energy Policy

Overestimating net benefit charges may render marginal hydro projects uneconomic, while the complexity and uncertainty of the approach may discourage potential hydro developers. Thus, the proposed rule is contrary to national energy policy as developed by Congress to encourage hydroelectric development. For example, under Title II of the Public Utility Regulatory Policies Act of 1978, P.L. 95-617, which is part of the National Energy Act, a guaranteed market for producers of small hydropower was established. Title IV of PURPA provided a loan program for small scale hydro projects. Section 405 of PURPA simplified licensing requirements for small hydro projects. The Energy Security Act, P.L. 96-294, Section 408, further expanded simplified licensing requirements, extended authorization for the hydro loan program, and authorized a study of existing policies relating to hydro. In addition, the Crude Oil Windfall Profits Act of 1980, P.L. 96-223, Section 242, established strong incentives to hydro development by providing an 11 percent investment tax credit, in addition to the regular 10 percent investment tax credit, for private hydro development.

Undisputedly, Congress has established a strong national commitment to hydro development. The proposed rule, by discouraging hydro development, runs counter to this national commitment.

IV. Inappropriateness of "Sharing of the Net Benefits" Method

In discussing the alternative methods for setting annual charges, the Notice of Proposed Rulemaking noted, "The Commission has concluded, first, that a generic net benefits method is most appropriate." APPA strongly disagrees with this conclusion.

The "sharing of the net benefits" method for determining the annual charge, whether it is generic or case by case, is not accurate. There are too many assumptions and estimates that have to be made over a 50-year period to result in an accurate determination of net benefits from the project.

For example, a public power system over a 50-year period will negotiate many power contracts and may refinance the bonds used to build the project. "Sharing of the net benefits" method cannot possibly track all these details over a 50-year period.

Second, "sharing of the net benefits" method does not reflect the true economic benefit to the developers. As discussed previously, the "sharing of the net benefits" method, which takes into account the tax-exempt status of public power systems, while not recognizing tax credits available to private companies, results in a tremendous dollar difference between the economic benefits the Commission determines to accrue to public power systems and what it determines will accrue to private power systems.

Such a method does not accurately account for benefits.

Third, "sharing of the net benefits" approach bears no relation to the cost to the government for allowing a nonfederal entity to develop hydroelectric power, and it will result in payment to the government in excess of any cost the government incurred in building the dam. Development of a federal dam is subject to congressional authorization. The costs of construction and operation have to be justified on a cost-benefit ratio before a dam is authorized. The project has to be beneficial to the government without consideration of future nonfederal development at the site. Nonfederal development at the federal dam does not in any way detract from the benefits already obtained by the government. The annual charge in this situation represents only the added revenues for the government and not repayment of cost. The hydropower licensee is merely making additional improvements at no cost to the government; the licensee is paying for all costs in addition to the annual charge.

Fourth, "sharing of the net benefits" is not reasonable nor is it consistent with the Federal Power Act. Under Section 10(e) of the Federal Power Act, a licensee is required to pay a reasonable annual charge. It does not appear to be a reasonable charge when there is a more than $200,000 difference in the amount a public system would pay in annual charges as illustrated in Vanceburg and the amount a private power company would pay in annual charges for the same project.

It would appear that the "sharing of the net benefits" method results in general revenue raising when it exceeds and bears no relationship to the federal government's cost for allowing a nonfederal entity to develop hydroelectricity. As interpreted by the court in Vanceburg, Section 10(e) was not intended to be a general revenue raising scheme.

In Vanceburg, although the court agreed that "sharing of the net benefits" was a valid approach to setting the annual charge, it was discussing the method on a case-by-case basis where the licensee is charged in proportion to the benefit "it actually receives." This is not the case in the proposed generic regional approach, which will use estimates and averages. Benefits under the proposed rule are not actually received, but only estimated.

In addition, the court was giving great deference to the "expert judgment" of the Commission. It did say "sharing of the net benefits" approach was not the only method to calculate the charge. The court said, in fixing such charges, the Commission has to consider balancing "all the relevant factors, including the impact of charges on consumer costs, the compensation of the Government, and the course of power development."

Applying that balancing test to the current proposal shows it will have a negative effect on power development, it will overcompensate the government in most cases, and it will increase consumer costs, especially consumers of public power systems which operate on a nonprofit basis and must pass on the cost of annual charges to their consumers.

V. Project Cost Determination

Determination of net benefits is directly related to project costs. It is thus essential that these costs be accurately determined. The proposed rule is inaccurate in its determination of project costs in that, while actual construction cost data would be used, some items would be excluded, such as Bureau of Reclamation payments and perhaps some environmental protection costs. In addition, operation and maintenance costs would only be averaged estimates.

To reflect accurately the true economic cost of the project, all project costs must be included. Yet, the proposed rule would not include payments made to the Bureau of Reclamation. In some cases, when the dam is a Bureau of Reclamation dam, developers make arrangements to pay for some or all of the costs of dam construction. The Commission's rule would not allow a credit for these payments in the project cost determination. A nonpersuasive reason given by the Commission for excluding these payments from project costs is, "These payments to BuRec would not qualify in nature as section 10(e) payments, which are intended to value economic benefits conferred by the Government by looking to the least costly alternative sources of power and the project powerhouse costs (not dam construction costs)." Not to include these payments will be to improperly ignore a real cost to the developer, which will result in an unfair assessment of the net benefits of the project.

Other items excluded from project cost determination may be environmental costs. Project costs are defined only in terms of "project powerhouse costs." However, project costs should include costs associated with required measures to protect and mitigate adverse impacts on environmental resources caused by the project. It is not entirely clear that such costs will be included in project costs. The proposed rule states that the project's developer will use costing standards set forth in the Uniform System of Accounts, 18 CFR Part 101. Although Account Nos. 330-332 of 18 CFR Part 101 allow for the cost of facilities and lands for fish, wildlife, and recreation, it is not clear if other environmental mitigation costs, such as environmental impact statements, can be included in the construction cost determination.

In addition to costs which may be excluded from project cost determinations, the operation and maintenance costs of a project will be an estimated average. Under the proposed rule, licensees will submit their own operation and maintenance cost estimates, and the Commission will use these estimates unless they depart "significantly from reasonable forecasts" based on standard industry data. In such case, the Commission will determine the most reasonable operation and maintenance cost estimates to use.

Operation and maintenance estimates from standard industry data are likely to be based on average projects and will not account for the significant variables of the operation and maintenance costs from one project to another.

Furthermore, these generalized data are likely to be incomplete and inaccurate or, at times, nonexistent. For those projects requiring costly, long-term maintenance, the actual operation and maintenance costs are likely to be significantly higher than average. If, in such a case, the licensee's own estimate were rejected, the resulting project cost and net benefits determinations would not truly reflect the licensee's long-term development costs, and, thus, the annual charge would be overestimated.

Last, the annual charge itself, which will be a major cost for operating the hydro system, is not included in the calculation for project costs.

VI. Determining Power Value and Least Cost Alternatives

The proposed rule will use average fuel costs, average cost of financing, and average investment costs to determine the power value for the hydroelectric project. The proposal states, "The power value of a hydropower project represents the cost of equivalent wholesale electric power from the least costly alternative source of power....Power value is the combination of capacity and energy values, corresponding to a realistic regional alternative generation source, which provides the lowest total power costs."

As referred to earlier, in determining power values, the proposed rule looks at the low cost financing available for public power systems to build a least costly alternative project, which will result in higher net benefits and, thus, a higher annual charge. On the other hand, the proposed rule does not include the tax credits available to private power companies as part of their benefits.

With respect to the regional approach, the Commission has not published the regions and power values in each region, so it is not possible to work out exact calculations on the effect of the proposed rule, but some generalities can be made. Basing the least expensive alternative source on average regional costs will not reflect the actual cost of the alternative for specific projects. For example, there could be significant variations within each region. One system's alternative to hydro may be natural gas, while another system's alternative in the same region may be coal. The specific characteristics of each system cannot be accounted for through regionalization. In addition, systems which are geographically near to each other could be in different regions. If fuel alternatives for each region are different, substantially different values could be assigned to their power value.

In addition, as the word "average" implies, this method will result in a figure between the highest and lowest cost of power in the region, which will not be the specific, actual cost for a specific project. Furthermore, it is not possible to forecast accurately future fuel costs and availability on a regional basis.

A. Capacity Value

Under the proposed rule, the capacity value of a hydro project "is estimated in terms of the project's peak season capacity factor and the comparative reliability of hydro and thermal power sources." The capacity factor of the hydropower is determined by hydrologic resource records which "can be used by a developer to calculate the average energy production expected at the project during the three-month peak load season."

Basing the peak season capacity factor on a statistical average will not determine the true peak season capacity. The peak season capacity factor can only be determined by detailed hydrologic studies and would be based on the most adverse or lowest water conditions, not the average. Averaging will result in a higher capacity factor than some water conditions and flows are capable of obtaining.

Furthermore, comparing the average peak season capacity of a hydro project with an equivalent thermal plant capacity does not account for the fact that hydro capacity will not be as dependable as an equivalent thermal plant. The only true comparison would be the actual hydro capacity available to meet the system's load under the most adverse water conditions. Thus, average peak period capacity overestimates the value of capacity from a hydropower resource.

In addition, there is more of an uncertainty about the peaking capacity of a hydro plant at a government dam since the licensee of the project has no control over water releases or future upstream uses. Therefore, relying on projected average annual energy data from resource records does not provide all the information necessary about future capacity due to changing conditions.

B. Illustrative Regions

As an example of different power values, the proposed rule uses New England and Wyoming, which are expected to represent the highest and lowest power value respectively. However, these regions have the least number of federal projects. It would seem to be more illustrative to use regions where there are a greater number of federal projects.

C. Fuel Prices

In determining the least cost alternative, the Commission under the proposed rule would escalate fuel prices for a 10-year period up to 1992. This inflates the power value by including future fuel prices in the initial year costs. In addition, the Commission would adjust the annual charge yearly according to the

GNP Deflator. The escalated fuel prices, coupled with the GNP Deflator, amounts to a double indexing and unreasonably inflates the annual charge.

VII. Application of Proposed Rule

A. Inflation Adjustment or Indexing

The Commission will adjust the annual charge yearly according to the GNP Deflator. Such an adjustment appears to be contrary to the provision of Section 10(e) of the Federal Power Act, which provides readjustment can only begin 20 years after a project is available for service.

In addition, as discussed previously, the proposed rule would include in the energy value of hydro projects estimates of future fuel prices for 10 years. This, along with the GNP Deflator, amounts to a double indexing and further inflates the annual charge.

B. Annual Update of Power Value Data

The Commission will issue an annual update of regional power values. The proposed rule does not establish a procedure for public participation in calculating regional power values or updates. There should be a procedure to challenge regional power values.

C. Relicensing

The same method used for calculating net benefits for new hydro projects will be used for calculating net benefits for relicensed hydro projects. The consequence of this will be an exorbitant increase in the annual charge for the relicensed project. Such a result will occur because the only project cost for a relicensed project would be minimal operation and maintenance, since, over the 50-year license period, the project will have already been paid for. Therefore, the charge will be half of the full power value, which will be significantly more than the amount charged under the initial license.

D. Option to Defer Annual Charge

The proposed rule would allow the hydro operator to defer the annual charge payment for the first 10 years if a statement from a certified public accountant verifies that project revenues for that year are less than the billed annual charge amount. To enforce this section, the Commission would have to establish another regulatory scheme and increase annual reporting requirements to determine if revenues exceed costs. Obviously, this will increase the burden of reporting on hydro project developers and will add another layer of bureaucracy to the process.

E. Nominal Annual Charge

Before construction is completed and the project is available for service, the Commission will charge a nominal annual fee of $100 starting with the project license term. However, Section 10(e) has been interpreted to mean that fees are not to be charged until the project is available for service. Section 10(e) provides that "after the project is available for service," a readjustment to the annual charge can be made in 20 years. This indicates that fees are not to be charged until the project is available for service. In accordance with that interpretation, the Commission has generally not charged an annual fee until the date the project is available for service.

VIII. Alternative Approach of Setting a Cap on the Amount Charged According to Installed Capacity and Energy Produced

In view of the inequities of a "sharing of the net benefits" approach, APPA recommends an alternative approach which would set a cap on the amount of the annual charge according to the installed capacity and energy produced from the project. That approach is reflected in a bill introduced in the Senate, S. 1132, which would specify that the annual charge for the use of a federal dam cannot exceed $1 per kilowatt of installed capacity and 1/2 mill per kilowatt-hour of energy produced. APPA believes that this charge, coupled with reimbursement to the government of actual operation and maintenance costs for the use of the federal facility, would be the most equitable and easily applied method of assessing annual charges. The Notice of Proposed Rulemaking dismisses this flat rate charge approach, saying it will not return enough money to the government. Actually, the flat rate method of S. 1132 will, on average, return more to FERC than the "sharing of the net benefits" approach used prior to 1979. Since then, FERC has, in some cases, set a cap on the amount which will be charged based on the "sharing of the net benefits" approach.

The average annual charge assessed by FERC prior to 1979 for the use of government dams was approximately $1.92 per kilowatt of installed capacity. Under the flat rate method of S. 1132, the charge would average out for those same projects to about $3.00 per kilowatt of capacity.

The method specified in S. 1132 will result in a predictable, yet reasonable, charge. The charge would depend on the specific characteristics of a project and would be proportioned to the value conferred by the federal dam. In addition, by setting a reasonable ceiling on the annual charge to be assessed, a potential developer can accurately and easily determine the economic feasibility of a particular project.

Setting a reasonable ceiling on the annual charge will meet the balancing criteria established in Vanceburg. It will have a positive effect on power development, it will compensate the government for the use of the dam, it will not adversely affect consumer costs, and it will not discriminate against public power.

Respectfully submitted,

Anne Marie Gibbons

by: Anne Marie Gibbons
Legislative Representative

AMERICAN PUBLIC POWER ASSOCIATION
2301 M Street, N.W., Third Floor
Washington, D.C. 20037

Dated: July 15, 1983

FERC CHARGES FOR USE OF FEDERAL DAMS

WHEREAS, local public power systems are actively seeking to develop the nation's clean and renewable hydroelectric resources, and

WHEREAS, the Federal Power Act provides for the Federal Energy Regulatory Commission to license a non-Federal entity to use a Federal dam for the generation of hydroelectric energy for a reasonable annual charge, and

WHEREAS, a reasonable annual charge is presently calculated as the payment of one-half of the difference between the cost of developing the hydroelectric generation and the cost of obtaining power from the least expensive alternative source such as a steam thermal plant, and

WHEREAS, the cost of building the hydroelectric generation at the existing Federal dam is borne solely by the non-Federal entity, costs the Federal Treasury nothing, and benefits the nation by offsetting the importation of foreign crude oil, and

WHEREAS, the charge calculated under this "sharing of the net benefits" method for use of the dam bears no relationship to the costs of the Federal government and may in some cases be so high as to discourage the development of the hydroelectric resource, and

WHEREAS, the Federal Energy Regulatory Commission is currently considering changing the method of calculating the fee for the use of a Federal dam by a non-Federal entity for hydroelectric generation;

NOW, THEREFORE, BE IT RESOLVED: that the American Public Power Association opposes the "sharing of the net benefits" method of computing charges for a non-Federal entity to use a Federal dam to generate hydroelectric power and urges the Federal Energy Regulatory Commission to adopt a nominal fee so as to encourage the rapid and full development of all potential hydroelectric capacity at Federal dams.

-- Adopted by the membership of the American Public Power Association at its annual conference in Washington, D.C., May 6, 1980.

STATEMENT OF MORGAN D. DUBROW, SENIOR STAFF ENGINEER, NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

Mr. **Dubrow**. Thank you, Mr. Chairman. I thank you for the opportunity to be here.

I speak for almost all of the thousand rural electric cooperatives.

In the statement that I will submit for the record, I must apologize. I overlooked a typographical error. The charge is $1 a kilowatt and a half-mill a kilowatt hour. Somehow it got to be 1 mill a kilowatt. I ask that be corrected.

We support this bill. We feel like it is reasonable and equitable. It collects more money than on the average than has been heretofore collected. I would simply like to comment that I think I heard General Wall say it was a nominal payment here. As a matter of fact, we developed the Columbia River with 2-mill power, $1 a kilowatt. A half a mill is almost 2-mill power. It is a mill and a half.

The problem is I would like to read what we have to say about this rule:

> The National Rural Electric Association, (NRECA) submits that this Notice of Proposed Rulemaking (NOPR), "Annual Charges for the Use of Government Dams and Other Structures Under Part I of the Federal Power Act," is contrary to the public interest and will result in inefficient and inequitable regulation. The NOPR will discourage future hydroelectric development rather than encourage it, and revenues to the federal treasury will decrease rather than increase. NRECA supports, in lieu of the proposal, a nominal fixed charge concept for capacity and energy that would encourage the maximum development of our nation's hydroelectric resources.

Now, that is what S. 1132 does. I must add one other thing. I found out, by receiving a copy of the testimony, that our people at Midwest Consumers, they advocated that the cap be modified to reflect what the allocated cost may have been had the Government built the dam.

I submit, Senator, that it produced an unnecessary complication which, in most cases, won't be as much money as we are advocating here.

I would therefore urge that the bill, as authored by you and the other Senators, those that were kind enough to introduce it, that you let it stand as it is.

I thank you very much for the opportunity to be here.

[The prepared statement of Mr. Dubrow follows:]

Statement of Morgan D. Dubrow
National Rural Electric Cooperative Association
on S. 1132
Before the Committee on Energy and Natural Resources
July 25, 1983

Mr. Chairman and members of the Committee, my name is Morgan D. Dubrow, Senior Staff Engineer of the National Rural Electric Cooperative Association (NRECA). We appreciate this opportunity to present a statement to the Committee expressing our views on S. 1132, a bill to amend the Federal Power Act to specify the annual charges for projects with licenses issued by the Federal Energy Regulatory Commission (FERC) for the use of Federal dams and other structures.

NRECA is a national service organization representing more than 1,000 rural electric systems in 46 states. These systems, mostly all cooperatives, serve more than 25 million consumers in 2,600 of the 3,100 counties in the United States, and distribute about 11 percent of the nation's electricity. Members of NRECA provide electricity to over 70 percent of the land area of this nation.

NRECA is pleased to support this bill. There are many Federal water impoundments which could accommodate hydroelectric facilities. Since the Federal Government has not built these potential power plants, a number of our member systems are installing power facilities at some existing Federal dams. In some instances, power will be used directly by the cooperative or it may be marketed through a Federal power marketing agency.

The critical need for energy in our nation today and for the near future necessitates the maximum use of falling water, a replenishing resource that is readily available at many existing Federal projects. This bill, S. 1132, will enable our cooperatives to go forward with the development of such power plants because the annual cost of the power facilities and thus the power rate can be determined at the outset.

We believe that it is proper for the licensee seeking to construct a power plant at an existing Federal dam or other facility to pay any added costs incurred by the Government, including all administrative costs for processing the license. NRECA is of the view that the additional charges of 1.0 mill per kilowatt plus 1/2 mill per kilowatthour are reasonable. Furthermore, the project costs will be finite; thus the licensee is assured that these are fixed charges which can readily be reflected in the overall project cost.

Our examination of the annual user charges heretofore assessed by the Commission (FERC) for power facilities at Government projects are on the average less than those set out in the bill. The primary objective is to develop power at these Federal projects, thereby using falling water energy that is going to waste. The power produced will have a nominal environmental impact because the power plants can be designed in such a way as to fit into the environment.

We believe that the Committee is aware of the proposed rule by FERC entitled "Annual Charges for the Use of Government Dams and Other Structures Under Part 1 of the Federal Power Act". Our Regulatory Counsel submitted NRECA's comments on this rule on July 15. A copy of these comments are attached. Our position is expressed in the Introduction as follows:

> "The National Rural Electric Cooperative Association (NRECA) submits that this Notice of Proposed Rulemaking (NOPR), 'Annual Charges for the Use of Government Dams and Other Structures Under Part I of the Federal Power Act,' is contrary to the public interest and will result in inefficient and inequitable regulation. The NOPR will discourage future hydroelectric development rather than encourage it, and revenues to the federal treasury will decrease rather than increase. NRECA supports, in lieu of the proposal, a nominal fixed charge concept for capacity and energy that would encourage the maximum development of our nation's hydroelectric resources."

In closing, we reiterate our support for S. 1132. We agree that the "economic viability is the heart of hydro power development". This bill provides for a reasonable cap on the charges to be imposed for the use of a Federal dam or other water facility for power production. It will enable a prospective developer to determine whether or not the project is viable.

We are pleased to add our support to this important legislation and appreciate the opportunity to appear before this Committee.

Attachment

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Annual Charges for the Use of Government Dams and Other Structures Under Part I of the Federal Power Act	)))	Docket No. RM83-13-000

COMMENTS OF THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

INTRODUCTION

The National Rural Electric Cooperative Association (NRECA) submits that this Notice of Proposed Rulemaking (NOPR), "Annual Charges for the Use of Government Dams and Other Structures Under Part I of the Federal Power Act," is contrary to the public interest and will result in inefficient and inequitable regulation. The NOPR will discourage future hydroelectric development rather than encourage it, and revenues to the federal treasury will decrease rather than increase. NRECA supports, in lieu of the proposal, a nominal fixed charge concept for capacity and energy that would encourage the maximum development of our nation's hydroelectric resources.

STATEMENT OF INTEREST

NRECA is a nonprofit service organization with a membership of about 1,000 rural electric systems. These member systems serve more than 25 million consumers throughout the United States, own and maintain nearly 44 percent of the nation's distribution lines, and distribute approximately 11 percent of the nation's electricity. Approximately 46 of NRECA's members are generation and transmission (G&T) cooperatives actively engaged in producing wholesale bulk power supplied to their distribution system member-owners. Many of NRECA's members are licensed applicants or are potential license applicants, and are therefore vitally concerned about this proceeding.

REVENUE STREAMS

It is the position of NRECA that there is little or no relationship between the proposed annual charges and the actual cost of administering the licensing process. Present Commission policy already provides for annual assessments for the administrative charges associated with licensing. The proposed annual charge is, therefore, nothing more than an unwarranted and unreasonable tax on electric consumers. Furthermore, the proposed annual charge would be so high as to discourage hydro development, resulting in less revenues to the government rather than more. As a case in point, the 15 MW Tuttle Creek Reservoir Project proposed by Kansas Electric Power Cooperative would be assessed more than $10 million during the 50-year life of a license. This estimate does not include annual rate of inflation escalations which are projected so far into the future that they cannot be considered reliable. Given such uncertainty, the wisdom of going foward with the project is questionable.

Additionally, the proposed annual charges would generate revenues that would exceed the amount paid by power users if the government constructed, operated, and marketed the power from the projects under current laws. This would result in an unfair disparity in the rates charged to consumers for power produced at federal versus non-federal projects.

NRECA submits that the Commission has a long established policy of basing electric rates on cost of service, and that Congress also reaffirmed this long standing principle when it enacted the Public Utility Regulatory Policies Act of 1978 (PURPA). The NOPR, on the other hand, would have the charges vary, based on indexes of uncertain future cost. In fact, the proposed indexing to the GNP deflator is contrary to Section 10(e) of the Federal Power Act, which provides that the annual charge can be readjusted at specified times beginning no earlier than 20 years after commencing operation. Finally, the use of indexing is poor economic policy.

ADMINISTRATIVE BURDENS

The procedures proposed by the Commission will substantially increase the reporting requirements of licensees, resulting in a corresponding increase in the time FERC must spend ensuring compliance. This problem is magnified by the fact that there has been little or no increase in the FERC technical staff in recent years, despite significant budget increases since 1977.

The problems enumerated above are compounded by a rule that is so complicated that it will increase controversy and further encumber the licensing process. In order to provide the necessary data, analyses and review of government statistical information, additional lawyers, engineers, accountants and financial analysts will be required. Additional burdens will be created by challenges to the annual Commission update of regional power value data.

INEQUITABLE CHARGES AMONG APPLICANTS

The Federal Power Act requires that licenses be granted to those applicants whose plans provide for the fullest and most efficient use of the resource. The present proposal, because of the artificial distinctions made among applicants, raises the possibility that this criteria will be ignored and that licenses will be granted to applicants with plans that will provide the greatest stream of revenue to the government.

CONCLUSION

The goal of any proposed rulemaking should be to simplify the regulatory process, resulting in (1) a reduction of administrative burdens, (2) a simple and easily understood rule, (3) equal consideration for all affected parties, and (4) compliance with the law being implemented. The NOPR fails to meet such a standard.

NRECA believes that a simple, straightforward approach, such as a flat rate annual charge of $1 per kW and 1/2 mill per kWh plus all extra expense incurred by the government resulting from the construction of the power plant, is preferable. This appears to be a fairer and more reasonable compensation to the U.S. Government for the use of this vital national resource.

Respectfully submitted,

July 15, 1983

Wallace F. Tillman
Regulatory Counsel
NRECA

Of Counsel:

Jay M. Galt, Esquire
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STATEMENT OF CLARENCE B. GRUND, JR., ASSISTANT VICE PRESIDENT, SOUTHERN COMPANY SERVICES, INC., ON BEHALF OF THE EDISON ELECTRIC INSTITUTE

Mr. GRUND. I am Clarence Grund, Jr., assistant vice president, Southern Company Services, Atlanta, Ga.

I appreciate the opportunity to appear before you on behalf of the Edison Electric Institute.

We heartily support and endorse S. 1132 because we believe that it will place reasonable constraints on the amount of annual charges while, at the same time, it will provide for a reasonable fee to the Government for the privilege of installing generating equipment at Government-owned projects.

It will expedite and simplify the currently burdensome process of establishing fees for hydroelectric power projects and it will serve the national interest by fostering the development of hydroelectric power at Government-owned dams.

Mr. Chairman, I could go on and elaborate, but the points I would make have been said by many people.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Grund follows:]

STATEMENT OF
CLARENCE B. GRUND, JR.
ASSISTANT VICE PRESIDENT
SOUTHERN COMPANY SERVICES, INC.
ON BEHALF OF
EDISON ELECTRIC INSTITUTE
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

July 25, 1983

Mr. Chairman and members of the Committee, my name is Clarence B. Grund, Jr., Assistant Vice President of Southern Company Services, Inc. I appreciate the opportunity to appear before you today representing the Edison Electric Institute (EEI) to discuss S. 1132, a bill which would define the maximum amount of annual charges which the federal government may charge licensees who use government dams or other structures to install hydroelectric generation.

EEI is the association of America's investor-owned electric utility companies. The member companies of EEI serve 99 percent of all customers of the investor-owned segment of the industry and 77 percent of all users of electricity in the United States. A number of our companies are licensed to operate hydroelectric power projects at federally-owned dams.

We are vitally concerned with the issues that are addressed by S. 1132, and we appreciate the attention being given to this measure by the Committee. Moreover, we heartily support and endorse S. 1132, because we believe that (1) it will place reasonable constraints on the amount of annual charges while at the same time providing for a reasonable fee to the government for the privilege of installing generating equipment at government-owned dams, (2) it will expedite and simplify the currently burdensome process of establishing fees for hydroelectric power projects, and (3) it will serve the national interest by fostering the development of hydroelectric power at government-owned dams.

The limit set forth in S. 1132 contains both a capacity component of $1.00 per kilowatt of installed generating capacity, and an energy component of one-half mil per kilowatt hour of energy generated at the hydroelectric project. The maximum fee established by the bill measures and varies the maximum allowable annual charge in direct proportion to the energy actually generated by the licensee. Thus, the maximum fee is directly related to the energy output of the hydroelectric project. Also, the bill consolidates the authority to assess charges in a single federal agency. The Federal Energy Regulatory Commission (FERC) would be free to assess a reasonable charge under Section 10(e) of the Federal Power Act so long as the annual charge does not exceed the limits established by the bill.

We believe that charges set under the provisions of the bill would provide a fair and adequate return to the government for the privilege of allowing the licensee to construct and operate hydroelectric facilities at government-owned dams. The bill requires the licensee to compensate the government fully for any unreimbursed costs resulting from construction, operation, and maintenance of the licensee's project works, in addition to the fee for use of the government-owned dam.

Currently, FERC sets annual charges during initial licensing and relicensing proceedings by determining what it considers to be the net benefits of the hydro project to the licensee, and equally dividing those net benefits between the licensee and the government. As applied by FERC, this net benefit determination is a burdensome, complex, and time-consuming undertaking. The net benefits determination has been hotly-contested and has resulted in considerable expenditure of FERC and licensee resources. Often the protracted litigation of net benefits has delayed the licensing process.

Earlier this year, FERC proposed to amend the case-specific application of its sharing the net benefits method, and proposed a generic region-based formula. Unfortunately, FERC's new proposal remains complicated, burdensome and time-consuming. It measures the licensee's net benefits in terms of hypothetical regional data and proposes annual indexing of charges. This will make economic analysis more difficult and can only result in a chilling effect on hydroelectric development. We have demonstrated in our comments on the FERC rulemaking that FERC's proposal would dramatically increase the level of annual charges to the detriment of both the nation and our ratepayers. We believe that the proposed FERC rule places an undue burden on the licensee and the ratepayer. In short, we feel FERC's trend toward use of increasingly complex and burdensome methods to set annual charges should be reversed.

The method contained in S. 1132 provides a simple, straightforward, easy-to-apply standard that would result in a maximum charge that is fixed. EEI believes that the method contained in S. 1132 and the consolidation of authority to assess annual charges in FERC would go far to reverse the increasingly complicated determination of annual charges, would limit the areas of disagreement between licensees and the government, and would expedite and simplify hydroelectric licensing.

As you know, hydroelectric power projects provide a low cost source of electricity that, in these times of increasing scarcity and higher fuel costs, should be strongly encouraged. Congress specifically recognized the need for this kind of power when it enacted Section 401 of the Public Utility Regulatory Policies Act (PURPA) (16 U.S.C. § 2701), which encourages the federal government to support the development of hydroelectric power projects on existing dams which are not now being used to generate electric power.

To foster development of hydroelectric power at government dams, and to maintain the economic viability of existing projects, it is imperative to set annual charges at a reasonable level, to set a charge that is fixed over the course of the license, and to adopt a method of computing annual charges that can be easily, and with some certainty, applied by the licensee. The limit proposed in S. 1132 will help to achieve these three objectives, and will permit a licensee to determine with assurance the level of annual charges that it will be called upon to pay from the projected income from the project. For these reasons we believe it is well suited for promoting the continued development of hydroelectric power at government dams.

The benefits that would flow from additional hydroelectric power can be substantial. On the local level, it will help our members keep down the cost of electricity to ratepayers and will allow utilities to spread the benefits of lower fuel costs among all consumers of electricity. On a broader level it will reduce the nation's use of and dependence on expensive imported fuels, and will help to stabilize the balance of payments.

Mr. Chairman, this concludes my prepared statement. I would be pleased to answer any questions you or the members of the Committee might have.

STATEMENT OF JOHN H. SPECHT, GENERAL MANAGER, GUADALUPE-BLANCO RIVER AUTHORITY; ACCOMPANIED BY BARBARA SCHNEIDER, CHAPMAN, DUFF & PAUL, COUNSEL TO THE ACPG

Mr. SPECHT. Thank you, Mr. Chairman, and members of the committee.

My name is John H. Specht. I am the general manager of the Guadalupe-Blanco River Authority of Texas.

I appreciate the opportunity to appear before you today.

With me also is Barbara Schneider of Chapman, Duff and Paul, counsel to the ACPG. She is also available to answer questions if there are any.

My statement today is in support of S. 1132 and I will summarize the position of the Annual Charges Policy Group and the Guadalupe-Blanco River Authority. However, I will refer you to the text of the written statement that is before you for further details, which I will submit at the end of this summary. My statement is also supported by the National Water Resources Association.

The ACPG is an association of 37 State water-user associations, irrigation districts, river authorities and other organizations located in 9 Western States.

Many ACPG members are operators of Bureau of Reclamation or Corps of Engineers dams and have applied for or received preliminary permits and licenses from the Federal Energy Regulatory Commission in order to develop the hydropower potential of these Bureau of Reclamation or Corps dams.

We support S. 1132 because it will provide the United States with reasonable compensation for non-Federal use of Government dams for hydropower generation, make a substantial contribution to repay the existing Federal investment in dams and reservoirs, and encourage non-Federal development in accordance with current Federal law and policy.

S. 1132 would modify section 10(e) of the Federal Power Act in two important respects to meet the congressional mandate of promoting hydropower development by non-Federal interests while avoiding increases in prices of power delivered to consumers.

First, S. 1132 would set a ceiling on the annual charge to be assessed by FERC.

Second, S. 1132 explicitly provides that the annual charge assessed by the FERC shall be the only charge assessed by any agency of the United States for a licensee's use of a Government dam or other structures owned by the United States for hydropower development.

Absent enactment of this bill, it is likely that further non-Federal hydropower development at Government dams will be severely constrained. This is because the FERC is in the process of implementing an annual charges methodology which, if promulgated as proposed, will result in extremely high annual charges.

We urge that this committee explicitly acknowledge the intent of S. 1132 to allow only a single charge for use of a Federal facility for hydropower purposes, and the amount of such charge would be that provided by existing contract and legislative authority, but limited by the maximum flat rate established by S. 1132.

This bill would provide increased revenues to the Federal Government without discouraging hydroelectric development by the non-Federal sector or unduly raising consumer power costs. It proposes a two-part calculation which provides a minimum fixed rental charge payable to the United States in years when below-average water flows limit the amount of power produced. In years when flows enable a project to produce a greater than average amount of power, the energy charge permits the United States to receive proportionately large revenues.

Another major objective to be accomplished by enactment of S. 1132 is the resolution of the longstanding question regarding the Federal Government's authority to assess an annual charge for a licensee's use of a Government dam to generate hydropower. There has been continuing uncertainty as to the, that is, as to whether the Bureau of Reclamation has the authority to assess a separate annual charge or "power privilege charge" for non-Federal hydropower development at Bureau of Reclamation facilities. A similar problem exists with respect to some Corps facilities where contracts or authorizing legislation provide for reallocation of costs for the addition of hydropower.

The threat of the potential for double assessment is a factor that discourages development and should be resolved by legislation rather than litigation. S. 1132 would eliminate this uncertainty by establishing that the fee charged pursuant to section 19(e) shall be the only fee charged to non-Federal entities for development of power at any Federal water facility.

I appreciate the opportunity, Mr. Chairman, to present this oral statement. Thank you, Mr. Chairman.

[The prepared statement of Mr. Specht follows:]

STATEMENT OF

JOHN H. SPECHT

GENERAL MANAGER, GUADALUPE-BLANCO RIVER AUTHORITY

Annual Charges Policy Group Membership

State Associations

Association of California Water Agencies
Idaho Water Users Association
Northwest Small Hydroelectric Association
Oregon Water Resources Congress
Utah Water Users' Association
Washington State Water Resources Association

Irrigation Districts, River Authorities and Other Participating Entities

Board of Control, Sunnyside Division of Yakima Project	Washington
Brazos River Authority	Texas
Calaveras County Water District	California
Central Utah Water Conservancy District	Utah
City of Redding	California
City of Santa Clara	California
Dodson Irrigation District	Montana
El Dorado Irrigation District	California
Friant Power Authority	California
Glasgow Irrigation District	Montana
Glenn-Colusa Irrigation District	California
Greenfields Irrigation District	Montana
Guadalupe-Blanco River Authority	Texas
Kennewick Irrigation District	Washington
Kings River Conservation District	California
Klamath Irrigation District	Oregon
Lower Tule River Irrigation District	California
Madera Irrigation District	California
Malta Irrigation District	Montana
Middle Rio Grande Conservancy District	New Mexico
Modesto Irrigation District	California
Ochoco Irrigation District	Oregon
Ogden River Water Users' Association	Utah
Sabine River Authority	Texas
Shoshone and Heart Mountain Irrigation Districts	Wyoming
Solano Irrigation District	California
Truckee-Carson Irrigation District	Nevada
Tualatin Valley Irrigation District	Oregon
Tumalo Irrigation District	Oregon
Weber Basin Water Conservancy District	Utah
Weber River Water Users Association	Utah

STATEMENT OF
JOHN H. SPECHT
GENERAL MANAGER, GUADALUPE-BLANCO RIVER AUTHORITY
ON BEHALF OF
THE ANNUAL CHARGES POLICY GROUP
AND THE GUADALUPE-BLANCO RIVER AUTHORITY
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
ON S. 1132

July 25, 1983

Introduction

Messrs. Chairman and members of the Committee, my name is John H. Specht, and I am General Manager of the Guadalupe-Blanco River Authority in Seguin, Texas. I appreciate the opportunity to appear before you today representing the Annual Charges Policy Group (ACPG) and the Guadalupe-Blanco River Authority to discuss the reasons why each entity strongly supports the passage of S. 1132.

The ACPG is an association of thirty-seven state water user associations, irrigation districts, river authorities and other organizations located in nine western states. For ease of reference, the individual members of the ACPG are listed following the cover page of this statement which is before you. Many ACPG members are operators of Bureau of Reclamation (BuRec) or Corps of Engineers (Corps) dams and have applied for or received preliminary permits and licenses from the Federal Energy Regulatory Commission (FERC or Commission) in order to develop the hydropower potential of these BuRec or Corps dams.

Congress has clearly stated its intent in prior legislation to promote hydropower development in this country by non-federal interests. See e.g., Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§2601 et seq.; Energy Security Act, Pub. L. 96-294. Congress has also expressed its intention to avoid increasing the price to consumers of power. See e.g., Federal Power Act (Act), Section 10(e), 16 U.S.C. §803(e). Against this backdrop of Congressional policies, Section 10(e) of the Act provides that all licenses issued by the FERC for the development of hydropower at government dams require the licensee to pay the United States a "reasonable annual charge" to recompense the government for the licensee's use of the dam.

S. 1132 would modify Section 10(e) of the Act in two important respects to better meet these important policies. First, S. 1132 would set a ceiling on the annual charge to be assessed by the FERC. Specifically, under this Bill the FERC would retain the discretion to specify a licensee's annual charge assessment of up to $1 per kilowatt of installed capacity plus 1/2 mill ($.0005) per kilowatt hour of energy produced. Second, S. 1132 explicitly provides that the annual charge assessed by the FERC shall be the only charge assessed by any agency of the United States for a licensee's use for hydropower development of a government dam or other structures owned by the United States. The balance of my statement is devoted to explaining why the ACPG and the Guadalupe-Blanco River Authority believe these two modifications to Section 10(e) are of critical importance to the non-federal sector's development of the nation's hydropower resources at federal water facilities.

The comments made on behalf of ACPG in Section I are intended to address that group's strong general support for S. 1132. The additional comments in Section II, made on behalf of the Guadalupe-Blanco River Authority, illustrate the benefits of and need for the proposed legislation in a specific case where a local sponsor has already contributed substantial sums to the construction and operation of a federal dam, and where the existing contract between the federal agency and the local sponsor already provides a specific method of cost allocation for the development of hydropower at a particular government dam.

I. ACPG COMMENTS

A. Background

Throughout the nation, there are hundreds of federal dams which provide essential public services, such as flood control, navigation, recreation, and conservation storage for irrigation, municipal and industrial uses. Most of these federal dams do not presently generate electricity, although hydropower production is generally both feasible and compatible with the existing operations of these dams. Estimates of the number of available hydropower projects at federal water facilities vary from 400 to 500 with a potential total installed capacity of approximately 6,000 to 13,500 megawatts. Thus, the renewable energy produced at these projects would displace millions of barrels of imported petroleum each year.

Despite the enactment of numerous statutes providing economic and regulatory incentives for the development of hydropower, and despite the increase in applications for FERC preliminary permits and licenses, actual development of these sites by the non-federal sector has proceeded at a very slow pace. One reason for this slow pace of development is that adoption of an annual charge methodology now being considered by the FERC will result in such a large annual charge that it will render many proposed projects economically infeasible. A second major reason is the inability of developers to predict the level of the annual charge to be assessed. An additional problem is the potential for dual annual charges for the use of a government dam being imposed by both the FERC and another federal agency.

The proposed legislation under consideration today, S. 1132, would solve these problems by setting forth a method for determining maximum annual charges that is readily calculable and is simple to administer. More importantly, this Bill would provide a fair return to the federal government without discouraging hydroelectric development by the non-federal sector or unduly raising consumer power costs.

B. Need For a Ceiling on the Annual Charge

Absent enactment of this Bill, it is likely that further non-federal hydropower development at government dams will be severely constrained. This is because the FERC is in the process of implementing an annual charges methodology (Docket No. RM83-13-000) which, if promulgated as proposed, will result in extremely high annual charges. The higher the charge level, the smaller the number of available projects that will actually be developed.

There are several reasons why excessive annual charges are undesirable. Many potential developers are districts and municipalities who have been given priority in such development in accordance with Section 7(a) of the Act. When such entities develop hydropower at federal water facilities, the costs of such development, including the costs of such charges, are passed through directly to consumers in the rates charged for this power. In addition, a high annual charge, not based on energy production, may provide severe cash flow difficulties for many developers in the early years and especially at facilities with run-of-the-river power generation in years of low river flow. Moreover, the FERC's proposed annual methodology can only be roughly calculated after analysis of a series of extremely detailed and complex and yet ultimately imprecise formulas.

In the ACPG's opinion, developers forced to comply with this inordinately complex FERC proposal will be unable to predict the level of annual charge assessed. Such uncertainty over the level of annual charge, a major cost factor, will cause many developers to put aside plans for development. Uncertainty as to the level of the annual charge also may prevent developers from obtaining financing for the substantial up-front costs associated with hydropower development, and this too, would provide an obstacle to further non-federal hydropower development.

C. Effect of S. 1132

We support S. 1132 because it will provide the United States with reasonable compensation for use of the government dam for hydropower generation, make a substantial contribution to the existing federal investment in dams and reservoirs, and encourage non-federal development in accordance with current federal law and policy.

S. 1132 would establish a ceiling charge of $1 per kilowatt plus 1/2 mill per kilowatt-hour. At a typical run-of-the-river facility located at an existing dam and operated at a 45 percent plant factor, this ceiling charge would equate to an annual charge of approximately $3 per kilowatt of installed capacity. Such a charge is over $1 more than the approximate average of fixed annual charges assessed by the Commission in the past. This is demonstrated by Exhibit A, attached hereto, which lists all available licenses containing fixed annual charges for use of government dams. The average of all such annual charges is $1.92 per kilowatt of installed capacity, which itself is reasonable compensation for government dam usage. By setting the maximum charge at a reasonable level which is over fifty percent higher than the average past annual charge, non-federal development will be encouraged and the total level of annual charge revenues accruing to the federal government will significantly increase.

S. 1132 proposes a two-part calculation based upon both installed capacity and actual energy production. The capacity portion of the charge provides a minimum fixed rental charge payable to the United States in years when below-average water flows limit the amount of power produced. In years when a project is able to produce a greater than average amount of power, the energy charge permits the United States to receive proportionately larger annual charge payments. The two-part charge permits the level of the annual charge to fluctuate in accordance with the power actually produced. Thus, a hydroelectric developer could avoid the severe cash flow problems which would result if a below-average water year results in a relatively low level of energy production and a licensee is subject to a high fixed annual charge.

Since all annual charges are ultimately borne by the electric consumer, the proposal will enable a portion of the benefits of hydroelectric power to be passed through to the consumers of electricity, in accordance with the requirements of Section 10(e) of the Act.

The S. 1132 approach permits developers to perform a single straight-forward calculation which can be planned for with certainty. It treats all licensees uniformly and allows for an annual charge that is a predictable and reasonable cost of doing business. A simplified approach and predictable reasonable annual charge level will encourage the use of existing public investments for developing renewable resources consistent with this nation's interest in energy conservation and energy independence.

D. Elimination of Dual Annual Charge Controversy

The second objective to be accomplished by enactment of S. 1132 is the resolution of the long-standing question regarding the federal government's authority to assess an annual charge for a licensee's use of a government dam to generate hydropower. The FERC's authority to assess an annual charge is provided under Section 10(e) of the Act. However, there has been continuing uncertainty as to whether the BuRec, under Section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. §484H(c), has the authority to assess a separate annual charge or "power privilege charge" for non-federal hydropower development at BuRec facilities. In comments recently filed with the FERC in response to its proposed annual charges rule, Docket No. RM83-13-000, the Department of the Interior asserted that it has such authority, stating that "[w]hen the [hydropower] site at issue involves the use of a Bureau facility, the Secretary can assess a power privilege charge in addition to FERC's annual charge". Alternatives For Determining Annual Charges For the Use of Federal Hydropower Sites, p. 4 (attachment to the Department of the Interior's comments in Docket No. RM83-13-000, undated.) A similar problem exists with respect to some Corps facilities where contracts or authorizing legislation provide for cost sharing reallocation of annual charges, which I will address in more detail in Section II, below. In any event, the uncertainty created by a possible double annual charge liability serves to discourage hydropower development at federal water facilities.

The ACPG believes that neither the legislative history of Section 9(e) nor federal case law provide any support for claiming that the BuRec has authority to assess a separate annual charge. Our position on that issue is stated in more detail in Exhibit B, attached hereto. The threat of this potential for double assessment, however, is a factor that discourages development and thus should be resolved by legislation rather than litigation. S. 1132 would eliminate this uncertainty by establishing that the fee charged pursuant to Section 10(e) shall be the only fee charged to non-federal entities for development of power at any federal water facility.

II. GUADALUPE-BLANCO RIVER AUTHORITY CONCERNS

In addition to representing the ACPG in this hearing today, I am also appearing before the Committee in my role as General Manager of the Guadalupe-Blanco River Authority (Authority) of Texas. The Authority is active in developing hydropower resources in the Guadalupe-Blanco River Basin and is presently seeking to add hydropower facilities to the Canyon Dam and Reservoir. Canyon Dam and Reservoir was constructed by the U.S. Army Corps of Engineers with the active participation of the Authority as local sponsor. The Authority's proposal to add hydropower facilities to Canyon Dam and Reservoir is an example which demonstrates the need for Federal Power Act amendments, such as those contained in S. 1132, setting maximum annual charges for use of a government dam.

Canyon Dam and Reservoir was authorized by Congress in the River and Harbor Act approved March 2, 1945 (Public Law 14, 79th Congress, 1st Session) as modified by the Flood Control Control Act approved September 3, 1954 (Public Law 780, 83rd Congress, 2nd Session). The 1945 authorization envisioned a purely federal project for flood control, water conservation and the possible addition of hydroelectric power, with no local cooperation required. Subsequent to the original authorization, the Corps, in close cooperation with the Authority, considered various designs and sizes of the project. The result of this planning and cooperation, as embodied in the 1954 Act, was a project that was almost $20 million below the cost of the multiple-purpose project which might otherwise have been recommended, and which provided substantial local involvement and contribution by the Authority. The Authority agreed to pay initially for the incremental cost of conservation storage and, by later annual payments, the full proportionate or allocated cost of conservation storage. As a result, the Authority paid $1.4 million, out of a total authorization of $13.3 million, and continues to make annual payments of $308,000 per year as well as bear the costs of 34.8% of all operation and maintenance costs.

The Corps decided against development of power in the original construction of Canyon Dam and Reservoir, but the 1954 Act provided the opportunity for the Authority later to add hydroelectric power facilities at the Authority's sole cost and expense, pursuant to the Federal Power Act and the 1954 Flood Control Act. The 1954 Act, and the Authority's contract with the U.S. Government, provide for reallocation of the costs of construction, operation, and maintenance among the various uses including the development of electric power at the time the Chief of Engineers determines that electric power facilities actually will be constructed. The Corps, in consultation with the Federal Energy Regulatory Commission, will reallocate the annual charge to be paid to the U.S. Treasury according to the Separable Costs/Remaining Benefits method of cost allocation.

The legislative history of the 1954 Act reflects that Congress was quite pleased by this arrangement. The House Committee Report noted the arrangement to be a "worthy new development, exemplifying a partnership between federal and state agencies in the developing of water resources." H.R. Rep. No. 2247, 83rd Cong., 2nd Sess. 125 (1954). The Committee also commended the Corps on its use of new and improved methods of cost allocation, which assure an equitable sharing of the cost between reimbursable and nonreimbursable project purposes.

Recently, the improved economics of hydropower development have led to renewed efforts to develop power at Canyon Dam and Reservoir. The Authority sought and received a preliminary permit from the FERC for this purpose, and is now preparing an FERC license application. Consequently, the Authority is now coming face-to-face with the FERC's March 31, 1983 proposed rule, Docket No. RM83-13-000, on the assessment of annual charges for the use of government dams by Commission licensees. 48 Fed. Reg. 15134 (April 7, 1983).

The FERC's proposed rule seems to be aimed at imposing what amounts to a double charge on projects such as Canyon Dam and Reservoir. There are two reasons why such an additional charge would not be proper. First, the Authority is paying the full share of the cost of Canyon Dam and Reservoir allocated to conservation storage, and should not have to pay an additional charge for the benefit of conservation storage for hydropower generation. Second, the 1954 Act and the 1957 contract between the Authority and the U.S. Government entered pursuant to the 1954 Act, already provide an explicit mechanism and methodology for establishing an annual charge resulting from reallocation of the costs of construction, operation and maintenance based on the benefits of Canyon Dam and Reservoir for hydropower generation. The FERC rule apparently would attempt to add additional charges based on a "sharing of the benefits" method without regard to payments already made toward Dam and Reservoir construction and maintenance. The Authority believes that such an additional charge is neither authorized nor warranted and has filed comments to that effect in the FERC rulemaking proceeding. However, legislation is needed to avoid the threat of protracted and costly disputes about this issue. We believe that S. 1132 is an appropriate vehicle to resolve many of the concerns raised by the FERC's proposed action.

The Authority believes that a local sponsor who has participated in paying for the construction of a federal dam by expending substantial funds toward construction costs and operation and maintenance, should receive recognition and credit in the establishment of annual charges. The Authority's annual charge should be the lesser of either the charges provided by contract or the maximum charge provided by S. 1132. The language of S. 1132 addresses this problem and is worded broadly enough to encompass our particular situation. S. 1132 would modify our present arrangement with the U.S. Government to the extent that payment would be made to the U.S. Treasury in an amount determined by FERC rather than the Corps. The amount of the charge would remain as agreed upon in the contract, but subject to the maximum charge limit specified in S. 1132. The Bill could not, of course, impair the rights of the Authority under the existing contract with the U.S. Government by increasing the charge to which the U.S. Government had previously agreed. A contrary interpretation would be inconsistent with the intent of S. 1132 to impose a maximum limit on the annual charge, and to prevent more than one agency of the government from imposing separate charges for use of the same government dam.

We believe that satisfactory resolution of the issue of annual charges for the use of a federal dam is vital to the development of this nation's hydropower resources. We support S. 1132 as a valuable and positive step in that direction, which is broad enough to cover the Authority's particular situation. We suggest that this Committee explicitly acknowledge the intent of S. 1132 to allow only a single charge for use of a U.S. Army Corps of Engineers Dam and Reservoir for hydropower purposes, and the amount of such charge would be that provided by existing contract and legislative authority, but limited by the maximum flat rate established by S. 1132.

I appreciate very much this opportunity to present testimony before you today.

EXHIBIT A

ISSUED LICENSES AT GOVERNMENT DAMS AND OTHER FACILITIES WITH FIXED ANNUAL CHARGES

Project Number	State	Capacity (kw)	Annual Charge ($)	Annual Charge ($/kw)
1517	West Virginia	1,120	375	.33/kw
2570	Ohio	40,000	50,000	1.25/kw
2614	Ohio	70,000	227,900	3.26/kw
13	New York	6,000	9,100	1.51/kw
289	Kentucky	80,320	95,000	1.18/kw
362	Minnesota	14,400	95,440	6.63/kw
1175	West Virginia	14,400	32,000	2.22/kw
1290	West Virginia	14,400	40,000	2.78/kw
2056	Minnesota	8,000	3,000	.38/kw
2165	Alabama	45,000	74,000	1.64/kw
2203	Alabama	40,000	67,200	1.68/kw
2211	Indiana	64,800	49,950	.77/kw
539	Kentucky	2,040	4,400	2.16/kw
2245	Kentucky	70,200	243,700	3.47/kw
2280	Pennsylvania	451,800	514,000	1.14/kw
2516	West Virginia	1,000	375	.38/kw

AVERAGE ANNUAL CHARGE: $1.92/kw

EXHIBIT B

Excerpt From Initial Comments
# of the
Annual Charges Policy Group
Regarding the Determination and
Assessment of Annual Charges at
Bureau of Reclamation Facilities

Submitted January 27, 1982
To The Commissioner of Reclamation
Department of the Interior

ACPG RECOMMENDATIONS

1. The Bureau Should Reassess the Legal Basis For Its Claimed Authority to Assess A Power Privilege Charge Upon Licensees at Bureau Dams

The construction, operation and maintenance of government dams which are part of Reclamation Projects are the statutory responsibility of the Bureau, pursuant to the Reclamation Act of June 17, 1902 (32 Stat. 388), and all acts amendatory thereof or supplemental thereto. The ACPG submits that the FERC, however, pursuant to Section 10(e) of the Federal Power Act, is the sole federal agency with the authority to impose any and all fees relating to the use of federal facilities for hydropower development. Moreover, once the FERC has determined whether a charge is appropriate and the amount of such charge, the Bureau cannot legally impose an additional charge for the use of the Bureau facility for the generation of hydropower.

It is the ACPG's understanding that the Department of the Interior believes it has jurisdiction to assess a separate annual charge or "power privilege charge" for non-federal hydropower developed at Bureau facilities. This presumed authority is premised upon the language of Section 9(c) of the Reclamation Project Act of 1939 which authorizes the Secretary of the Interior to permit "the lease of power privileges . . . in connection with the operation of any project or division of a project . . . at such rates as in his judgment will produce power revenues at least sufficient to cover an appropriate share of the annual operation and maintenance cost, interest on an appropriate share of the construction investment at not less than 3 per centum per annum, and such other fixed charges as the Secretary deems proper . . . ."

The ACPG submits that Interior's reliance upon Section 9(c) for authority to assess a separate annual charge is erroneous. 7/ Neither the legislative history of Section

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7/ The sole opinion located which arguably supports an expansive interpretation of Section 9(c) is an opinion of the Solicitor of the Interior, Subject: Authority to sell falling water, dated April 12, 1955. However, in this opinion, the Solicitor merely construed Section 9(c) to be "sufficiently broad in scope to comprehend a so-called sale of falling water or such other arrangement as may be undertaken contractually for non-Federal construction or operation, or both, of power facilities to utilize power head and storage at, or operationally in conjunction with, Federal reclamation dams." (emphasis supplied).

9(c) 8/ nor federal case law provide any support for the argument that Section 9(c) provides the basis for the Bureau's assessment of a separate annual charge.

Where a non-federal developer obtains a FERC license to construct, operate and maintain a hydropower facility at a Bureau dam, this non-federal developer has not *leased* a power privilege from Interior. The language of Section 9(c) supports an interpretation that Congress was merely conveying to the Bureau the authority to lease any power privileges it possessed by virtue of congressional authorizations of specific reclamation projects. Thus, if Congress authorized the Bureau to develop power at a reclamation project and it failed to develop the project power or wished to transfer development to a non-federal entity, then, pursuant to Section 9(c), the Bureau could lease the power privilege to that non-federal entity. 9/ The failure of the legislative history to mention the FERC (then the Federal Power Commission) supports the view that Congress intended the lease of power

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8/ Sources of legislative history examined include: (1) H.R. Rep. No. 995, 76th Cong., 1st Sess. (1939); (2) S. Rep. No. 758, 76th Cong., 1st Sess. (1939); (3) H.R. Rep. No. 1252, 76th Cong., 1st Sess. (1939); (4) *Reclamation Project Act of 1939, Hearings on H.R. 6773 Before the House Committee on Irrigation and Reclamation*, 76th Cong., 1st Sess. (1939); (5) *Reclamation Project Act of 1939, Hearings on S. 2591 Before the Senate Committee on Irrigation and Reclamation*, 76th Cong., 1st Sess. (1939); (6) Congressional debates on the Reclamation Project Act published in the federal register; and (7) Report of the Special Repayment Commission Appointed to Devise a More Equitable and Flexible Permanent Plan for the Repayment of the Construction Cost of Federal and Indian Reclamation Projects, H.R. Doc. No. 673, 75th Cong., 3rd Sess. (1938).

9/ This interpretation is consistent with both the language contained in the Solicitor's memorandum dated April 12, 1955, *see* n.5 *supra*, and a more recent Solicitor's Opinion, Subject: Disposition of the Land Use Portion of Federal Energy Regulatory Commission License Revenues, dated June 9, 1981. In this latter opinion, a clear distinction is drawn between Interior's authority to dispose of revenues received in connection with leases of power privileges and its lack of authority to control the disposition of annual charges assessed under Section 17 of the Federal Power Act.

privileges authority to be a different and separate power than that given to the FERC pursuant to Section 10(e) of the Federal Power Act. If Congress had intended to limit or modify the Federal Power Commission's licensing powers in the enactment of Section 9(c), the effect of such a major modification of the Federal Power Commission's authority under the Federal Power Act would necessarily have been the subject of Congressional debate.

Moreover, the assessment by Interior of a separate charge upon licensees of projects at federal facilities would necessarily decentralize federal control over hydropower development. Such a result would be contrary to Congressional intent in enacting the Federal Water Power Act of 1920 in the first instance. This law was enacted for the express purpose of centralizing federal regulation of hydropower in the belief that a single federal voice could best achieve the goal of comprehensive development of this nation's water resources. *See First Iowa Hydroelectric Cooperative v. FPC*, 328 U.S. 152 (1946). *See also FPC* v. *Union Electric*, 381 U.S. 90 (1959); *Northwest Paper Company* v. *FPC*, 344 F.2d 47 (9th Cir. 1965); *Monongahela Power Company* v. *Alexander*, No. 78-1712 (D.D.C., issued December 19, 1980), *appeal pending*, *Monongahela Power Co.* v. *FERC*, No. 81-1201.

The legislative history and case law construing Part I of the Federal Power Act clearly indicate that the FERC has exclusive jurisdiction over the development of all hydroelectric projects subject to its jurisdiction. *See e.g.*, *First Iowa Hydroelectric Cooperative* v. *FPC*, *supra*; *City of Tacoma* v. *Taxpayers of Tacoma*, 357 U.S. 320 (1958). Although Section 10(e) of the Federal Power Act requires the FERC to give serious consideration to Interior's (and the Bureau's) comments relating to the fees charged for the use of Bureau facilities, the FERC, pursuant to Section 10(a) of the Federal Power Act, has ultimate authority to determine all terms and conditions which will be a part of the license, including the amount of any and all charges imposed. If Interior is dissatisfied with the FERC's determination with respect to the charge assessed, it can express its disapproval of the license by seeking federal court review of the FERC licensing order. *Montana Power Company* v. *FPC*, 459 F.2d 863, 874 (D.C. Cir. 1972).

STATEMENT OF THOMAS C. HOUGH, PRESIDENT, HOUGH ASSOCIATES

Mr. Hough. Thank you, Mr. Chairman. I will summarize my written testimony.

I am president of a research and consulting firm that specializes in energy work. I am also a member of the board of directors of the National Hydropower Association, which is a trade association of the private hydropower developers.

In a recent study I took some data from the National Hydropower Study. I analyzed existing Federal dams where potential hydropower projects could take place.

Of the 345 existing Federal dams we identified, really, 235 that could economically produce a rate of return that would be for development by private entities. Of these, 158 have either been granted licenses or are in the licensing process. That statistical data was handled in such a way that the projects were predicted on a general sizing methodology and a flat rate of 5 cents per kilowatt hour, which does not exist, really, on a nationwide basis.

If those 235 dams were developed, it would produce just under 4,000 megawatts of new capacity in the United States and this would generate 17.3 hours of energy in an average water year.

Using the uniform charge methodology proposed in S. 1132, we would collect perhaps about a half billion dollars over the life of all these facilities through the Federal dam charges.

I looked at the computer programs that I had to look at the FERC "half the benefit method." I found it very complex. It would be very difficult to forecast all of the energy alternatives that would be necessary to make a calculation for each entry for those 235 dams.

If any of these dam charges were put on a project it would reduce the marginal economics of the project. The charges proposed in S. 1132, as to those, it doesn't appear that they would stop any of the projects, whereas the charges under the FERC method may, in fact, stop some projects because their current method of assigning the dam charges is unrelated, really, to the returns to the developers. So, a marginal project may be charged with a significant charge where a project that may be very profitable may not be charged very high under the FERC methodology.

The hydroelectric power industry already pays 50 percent in taxes. It pays Federal taxes of a substantial amount on its net income and additional dam charges, we feel, are unwarranted here. We are willing to pay a reasonable charge in S. 1132.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Hough follows:]

HOUGH ASSOCIATES
One Bala Plaza
Bala Cynwyd, Pennsylvania 19004

THOMAS C. HOUGH
President

215-667-8611

Statement of Thomas C. Hough
before the
United States Senate
Committee on Energy and National Resources

Mr. Chairman and members of the committee, my name is Thomas C. Hough. I am the president of Hough Associates, a research and consulting firm, specializing in energy. I direct hydroelectric project activities for National Property Analysts, a major developer of commercial real estate. I am a member of the Board of Directors of the National Hydropower Association (NHA). NHA is the trade association of the private hydropower industry, and its members include hydropower project developers, engineering consultants, equipment suppliers and other interested parties. I am accompanied by Peter Smith, a director of NHA. I appreciate the opportunity to provide testimony on recent analysis performed by my firm on annual charges for the use of federal dams for hydropower.

An inventory of the 345 existing federal dams was compiled from data collected in the National Hydropower Study by the Institute of Water Resources of the U.S. Army Corps of Engineers. These data were analysed and 257 federal dams were identified where more than 1 megawatt of capacity could be installed. The capacity of each site was determined by net head and mean stream flows. Capital and operating costs were assigned to each project as a function of the cost estimates in the National Hydropower Study. Those dams that could produce a 12% gross rate of return at 5¢ per kilowatt hour were identified. FERC data indicate that 41 licenses were granted and 117 licenses are pending on federal dams, which is the ultimate evaluation of economic potential.

HOUGH ASSOCIATES
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THOMAS C. HOUGH
President

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NATIONAL HYDROPOWER STUDY DATA

FEDERAL DAMS

Federal dams in active inventory	345
Dams with more than 1 MW additional capacity at mean stream flow	257
Economic dams (12% gross return)	235
Licences granted	41
Licences pending	117

Economic Federal Dams

Number of dams	235
Total capacity	3,951 MW
Average annual energy	17.3 MWH

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Bala Cynwyd, Pennsylvania 19004

THOMAS C. HOUGH
President

215-667-8611

The 235 federal dams in the sample have a predicted 3,951 megawatts of capacity and would produce 17.3 million megawatt hours in an average water year. Using the uniform charge structure proposed in S.1132 federal revenues from capacity charges would be $3.95 million. The annual revenues from energy charges would be $8.65 million. Over the 50 year license life of these projects, total dam charges under the proposed scheme would be about ½ billion dollars.

It was not possible within the scope of the study to analyse the tax revenues that might be collected under the FERC "half the benefit" method. This method involves complex regional forecasts of energy alternatives and future fuel costs. The result of this charge may actually decrease federal revenues if marginally economic projects were stopped.

The current method of assigning dam charges by the FERC creates uncertainty and inequities. Since "benefits" as defined by the FERC proposed rule are unrelated to returns to the developer, it may be possible to assign large charges for "benefits" at marginal projects, while profitable projects could have no "benefit" under the formula. Uncertainties make financial planning difficult when private developers are unable to accurately determine the cost of FERC charges for their projects. While any charge reduces the economic returns of an investment at federal dams, the proposed method should not deter development of these resources.

The private hydroelectric power industry already pays federal taxes on project net incomes. The addition of potentially excessive dam charges is unwarranted. The hydropower industry requests that S.1132, which sets reasonable and certain charges be passed.

STATEMENT OF GRANVILLE J. SMITH II, PRESIDENT, ENERGENICS SYSTEMS, INC.

Mr. SMITH. Mr. Chairman, my name is Granville Smith. I am president of Energenics Systems, Inc., a small company that is devoted to hydroelectric development.

In the past 2 years we have analyzed 60 or more hydroelectric projects, potential hydroelectric projects, at Federal dam sites.

We currently have two licenses to construct and operate projects. We have five licensed applications pending. Also, 22 projects are in various stages of feasibility studies.

I might say, before commenting specifically, that is, on S. 1132, that, in order to do these feasibility studies and these investigations, we had to work in close cooperation with the Corps of Engineers and the Bureau of Reclamation. In fact, we had to sign agreements with them to reestablish an escrow account in which we paid up-front money which reimbursed the Federal Government for all of their costs, the engineering costs, their personnel costs and out-of-pocket expenses, and so forth. We think this is a reasonable way to do business, quite frankly.

With respect to the seven projects on which we have the licensed applications, we have analyzed those projects economically, using your proposed charges in S. 1132 and using the FERC proposed regulations and annual charges. Quite frankly, had we known what the first proposed regulations were going to be before we filed for the licenses, we then probably would not have filed for them, or we would have done so after a lot more consideration. What happens under the proposed FERC regulations is that the net revenue, and by net revenue I mean the gross revenues, the annual operating costs, the debt charges, and with no payment from my company in any way, that they turn out to be negative. That is in six out of seven projects. The seventh one is awfully close.

Now, that is not just in the first year. In some of the projects that is true for the first several years of the project.

On the other hand, if we use your proposed charges, then six out of the seven projects have positive net revenues. What that says to me is that I would go ahead and propose to build those projects under S. 1132, whereas I certainly would not under the FERC annual charge rule.

Let me repeat also that the, and this is because many other people said it here, which is that, and this is a point worth making, and that is the uncertainty of the FERC regulations, that this creates severe complications in trying to finance the power projects. S. 1132 removes that uncertainty and makes financing these projects a more reasonable task.

Obviously, Mr. Chairman, we strongly support the passage of S. 1132 as it is currently written.

Thank you, Mr. Chairman. I submit my statement in full.

[The prepared statement of Mr. Smith follows:]

TESTIMONY OF GRANVILLE J. SMITH II, PRESIDENT
ENERGENICS SYSTEMS INC.
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
JULY 25, 1983

Mr. Chairman, my name is Granville Smith. I am President of Energenics Systems Inc., a small business devoted to the development of hydroelectric projects. We are located in Washington, D.C.

Energenics has, over the past two years, analyzed the economic and technical feasibility of over 60 potential hydroelectric projects located at Federal dam sites. Energenics is the licensee for the construction, operation and maintenance of powerplants at two Federal sites in Colorado and has five license applications pending before the Federal Energy Regulatory Commission (FERC) for projects located at other Federal facilities. In addition, Energenics currently holds 22 FERC permits to investigate the feasibility of hydroelectric power projects at 22 different Federal dam sites. Feasibility studies are underway on these 22 sites. Consequently, Energenics has a direct and significant interest in the legislation currently under consideration.

Mr. Chairman, Energenics Systems very much supports the passage of Senate bill S.1132. It clarifies an issue which has created significant financing problems for us by providing a simple, reasonable formula for annual charges at Federal facilities. Without S. 1132 determination of the economic feasibility of a potential hydroelectric project at a Federal dam site requires guessing the magnitude of the Federal charge. Such guesses create unacceptable risks and financing for such projects becomes very difficult.

The FERC has proposed regulations which set an annual charge for the use of Government dams and other structures. In its comments to FERC on the proposed regulations, Energenics emphasized that the proposed regulations are very complex, do not adequately account for current financing terms, do not account for any differences in size of hydroelectric projects, and require the project developer to make projections about the utility industry which are highly technical and require sophisticated computer-based analysis. Most importantly, the seven projects for which Energenics is either licensee or has submitted a license application have been analyzed economically and six of the seven projects have a negative cash flow in at least the first year of operation. Had FERC's proposed regulation been issued before we applied for these licenses, we would have had serious doubts about their economic feasibility and may not have applied for licenses on any of them. The annual charge proposed by FERC clearly creates serious financing problems for the private or municipal developer.

The annual charge formula proposed in S.1132 is a much more sensible and perferable solution. It is simple and can be easily understood by potential project financiers. It does not require sophisticated analysis or guesses about the future growth of the utility industry. At the same time, it provides an annual charge based on size and energy output so that the smaller projects, which generally have much less financial flexibility than larger projects, pay less. For the seven projects mentioned above, the annual charge formula proposed in S.1132 improves their economic viability and, therefore, allows projects to be built which would be economically infeasible under the FERC proposed annual charge. Energenics strongly supports the passage of S.1132.

In its comments to FERC on their proposed annual charge, Energenics noted that the Federal Government has used a deferred payment plan to encourage development. For example, the payments required of irrigators who receive water from a new Federal irrigation system are sometimes deferred for a ten year period. The deferral allows the irrigator time to fully develop the irrigated land before payment is required. Similarly, in the early years of many small hydroelectric projects, revenues are very low and a deferral plan would encourage development. Since any hydroelectric project has a very long life, the Federal Government would still collect annual charges over most of the project's life; whereas, if the project is not constructed, the Government would receive no annual charges. The Committee should consider the value of adding a provision to S.1132 which provides for a ten year deferred payment plan for projects under five (5) megawatts.

Thank you, Mr. Chairman, for this opportunity to comment on S.1132. I have provided your staff with copies of our comments on the FERC proposed annual charge regulations. If the Committee wishes additional information, I would be happy to provide it.

The **Chairman**. Thank you, gentlemen, for your testimony. I only have a couple of questions.

I would like to allow Senator Melcher as much time as possible.

You said, Mr. Specht, that there should be the only charges specified in the bill. Did you mean to exclude from that the additional cost to the Government of construction or supervision, or if there are additional costs?

Mr. **Specht**. No; to the extent there are those costs, I certainly think those are legitimate and that they should be paid by the developer.

The **Chairman**. Thank you very much.

Mr. **Specht**. Yes, sir.

The **Chairman**. I appreciate the endorsement that we had from this panel for the legislation. It isn't often that we see the APPA, the NRECA, and the Edison Electric Institute all sitting together. It almost scares me.

Now, Mr. Specht, on page 5, you made a statement that kind of summarizes in some respects the concerns that have been expressed by many, and which I endorse. The higher the charge level the smaller the number of available projects that will actually be developed. I think that is the bottom line if we are really concerned about getting these online.

Go ahead, Mr. Melcher.

Senator **Melcher**. Thank you, Mr. Chairman. I just wanted to get the opinion of this panel. In the past there have sometimes been differing opinions. They are together at the same table advocating the same thing at the same time.

I am very much pleased and encouraged. I think that your bill, Mr. Chairman, does allow for the Congress to consider the opportunity of simplifying the procedures and keeping them within the framework of reasonable cost. We can then get on with the business of producing more hydropower. I think it is about time that we did.

The **Chairman**. Thank you very much, Senator Melcher. I appreciate your attendance and your efforts with respect to this hearing today.

A letter from the city of Santa Clara, Calif., dated July 21, 1983, from Barry R. Flynn and a statement by the Louisville Gas & Electric Co., dated July 25, 1983, will be placed in the record at this point.

[The material submitted by the chairman follows:]

THE CITY OF SANTA CLARA
CALIFORNIA

ELECTRIC DEPARTMENT
CITY HALL
1500 WARBURTON AVE.
SANTA CLARA, CA. 95050
(408) 984-3161

July 21, 1983

Mr. Howard Useem
Room S. O. 306 Dirksen
Dirksen Senate Office Building
Washington, DC 20510

Dear Mr. Useem:

Enclosed are fifty copies of a statement I intend to present at the July 25 hearing before the Senate Committee on Energy and Natural Resources regarding Senate Bill 1132.

Sincerely,

Barry R. Flynn

Barry R. Flynn
Director of Electric Utility

Enclosure

STATEMENT
BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

BY

MR. BARRY R. FLYNN
DIRECTOR OF ELECTRIC UTILITY
CITY OF SANTA CLARA, CALIFORNIA

JULY 25, 1983

STATEMENT
BY
MR. BARRY R. FLYNN
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
WASHINGTON, DC
JULY 25, 1983

INTRODUCTION

Mr. Chairman and Members of the Committee. My name is Barry R. Flynn, I am the Director of Electric Utility for the City of Santa Clara, California which operates a California municipal utility serving over 40,000 customers.

In 1982, the City of Santa Clara utility system had a peak demand of 297 MW and provided over 1.8 billion kilowatthours of energy to serve the needs of the City's utility customers. The City receives a portion of its power supply from the federal Central Valley Project, marketed by the Western Area Power Administration (Western). A small portion of the City's power comes from a recently constructed City-owned 6 MW cogeneration project. The balance of the City's power is supplied through wholesale purchases from Pacific Gas and Electric Company (PGandE).

The City of Santa Clara is undertaking an active program to develop its own utility resources to reduce and ultimately eliminate the need for purchasing power. The objective of this program is to secure long-term, low-cost power for the City's utility customers using renewable energy resources to the extent possible. In my brief comments today, I wish to emphasize the importance of the development of small hydroelectric projects at federal dams as an integral portion of the City's efforts to develop its own power supply resources. I further wish to explain how the basis for establishing federal annual dam use charges under the Federal Power Act is an important consideration to the future of small hydroelectric development.

Role of Small Hydroelectric Projects in Power Supply Development

As a utility which has historically purchased a large majority of its power needs, the City of Santa Clara sees small hydroelectric projects as a favored resource for commencing a well planned path of development of its own power supply resources to meet the needs of its utility customers. Small hydroelectric projects are expected to provide a basis for the City to develop other renewable energy resources to reduce its purchases of wholesale power and gain control over its future power costs.

The City's near-term alternative cost of power is wholesale power purchases. The majority of small hydroelectric projects would result in project power costs which are higher than wholesale power costs in the near term. Therefore, for the City to incur the risk of higher power costs now, with the expectation of lower long-term costs, it is important that federal dam use fees not be so high as to create a disincentive to develop these important renewable energy projects.

Uncertainty Over Federal Dam Use Charges

The City filed preliminary permit applications for two projects at federal dams (Stony Gorge, Project No. 3193 in Glenn County, California and Black Butte, Project No. 3190 in Tehama County, California) in May of 1980. In its analyses of the feasibility of these projects, the City solicited from the FERC some indication as to the federal dam use charge likely to be applied under Section 10(e) of the Federal Power Act. The FERC could give no indication as to what the charge might be as it had not established a procedure by which it would set such charges. Operating under the assumption that the FERC would not establish a fee which would significantly impact project economics, the City proceeded with its feasibility studies, environmental studies, and project licensing. The City received a license for the Stony Gorge project in August 1982 and for the Black Butte project in May of this year.

After substantial expenditures by the City for studies, geotechnical testing, state and federal permitting, and preliminary project design, the FERC has still not indicated to the City the fee that it intends to assess against the projects for use of the federal dams. When the FERC issued its proposed rulemaking (RM83-13-000) on March 31, 1983 to establish the basis for determining the annual dam use charges, the City was hopeful that the uncertainty over the fee which has prevailed over the last three years would finally be eliminated. Unfortunately, due to the nature of the proposed FERC rule, the City and other licensees and applicants are still not in a position to confidently estimate their annual fees. In light of the uncertainties regarding future alternative power costs, costs of financing, and construction cost escalation, the City feels that it is prudent for an annual dam use charge to be established which does not contribute to this environment of uncertainty.

Summary of Concerns with the Proposed FERC Rule

The City of Santa Clara has submitted detailed comments on the pending proposed rulemaking by the FERC regarding the determination of annual dam use charges. Due to the rather involved nature of the comments filed by the City in response to a complex economic formula, I will not discuss these comments in detail. However, I would like to provide a brief summary of the City's concerns with the proposed rule and indicate the City's reason for support of the formulated limit on such fees proposed in Senate Bill 1132.

The City's main concerns with the proposed rule are as follows:

1. The rule is based on the concept of setting annual use fees equal to 50 percent of a theoretical net benefit of the projects. The substantial fees expected from such a formula ignore the risk taken by the licensee in developing the project and impose a strong disincentive to develop small hydroelectric facilities.

2. The proposed formula ignores actual power values available to project licensees and thereby is expected to establish inequitable fees between different licensees.

3. The proposed rule ignores tax benefits available to private entity licensees and is expected to result in substantially lower annual dam use charges for private licensees than for public licensees.

4. The FERC's proposed formula will use regional power values to be established in the future by the FERC upon which the actual annual dam use charges will be established. Absent a determination of these power values in advance, licensees cannot confidently predict the annual charges prior to the adoption of the rule. Therefore, neither the licensee nor the FERC can be certain that the dam use charges will not be economically burdensome or in the extreme, result in making a project economically infeasible.

Endorsement of a Simplified Formula

The formula for the annual dam use charge proposed in Senate Bill 1132 is a formula which the vast majority of small hydroelectric projects at federal facilities could economically support. Unlike the formula in the proposed FERC rulemaking on this topic, the formula proposed in Senate Bill 1132 would meet the following important objectives established by the FERC in its notice of rulemaking:

1. It would provide certainty to applicants and licensees regarding applicable fees.

2. It would limit the administrative burden on the FERC in setting such annual charges by establishing a simplified formula.

3. The formula would provide for income to the U.S. Government in all years of project operation with the amount of such charges directly related to the capacity and energy available from projects subject to such charges.

The City of Santa Clara strongly endorses Senate Bill 1132 as legislation which would eliminate a major uncertainty in small hydroelectric development. Furthermore, this legislation would preclude the FERC from establishing dam use charges which could create a disincentive to develop needed hydroelectric projects at existing federal facilities.

Statement by Louisville Gas and Electric Company
Senate Energy and Natural Resources Committee
July 25, 1983
S. 1132

LG&E is an investor-owned utility that owns, operates, and maintains an 80,000 kw hydroelectric project, known as the "Ohio Falls" project, at the United States Army Corps of Engineers' McAlpine Lock and Dam, on the Ohio River. LG&E provides electric service to approximately 300,000 customers in and around Louisville.

The hydro plant was built in 1925, and the original license for its operation expired in 1975. In 1981 FERC issued LG&E a new 30-year license for the operation of the plant. Approximately 95% of the Company's electric output is produced by steam generation and the remaining 5% is produced by the hydro plant.

Under the original license, the fee for use of the government dam adjacent to the hydro plant was $95,000 per year. The new license issued by FERC in 1981 provides that the fee for use of the dam will be determined by FERC sometime in the future and establishes $2.621 million per year as an upper limit to that fee. FERC's arguments in court suggest that the new fee will be little, if any, below the $2.621 million ceiling. In a ruling which has been challenged by LG&E in the Courts, FERC has determined that the new fee, once established by FERC, will be retroactive to 1981, the effective date of the new license.

Our facility is 50 years old and we feel that a charge based on a formula not to exceed one dollar per kw of installed capacity and 1/2 mill per kwh of energy produced as contained in SB 1132 to be more fair than the burdensome and uncertain calculations associated with the formula as proposed by FERC in the Docket #RM83-13-000.

It is our position that the formula contained in S. 1132 is more desirable in that it minimizes the cost to the consumer, yet fairly compensates the government to some extent for benefits received by the licensee. The formula in S. 1132 would result in an annual fee of approximately $300,000.

Sec. 10(e) of the Federal Power Act states in general that charges paid by the licensee of a hydroelectric project of a federal dam be "reasonable." However, it also states that "in fixing such charges, the Commission shall avoid increasing the price to the consumer of power by such charges."

We believe that the increase in charges proposed by S. 1132 would certainly be a much more reasonable burden on our customers and much more in line with the increase in the cost of living that has taken place since the plant was first licensed in 1925. Furthermore, it seems to conform more closely to the concept, expressed by both the Federal Power Act and the Courts, that fees of this sort should be set so as to minimize the burden on consumers.

Failure to implement the formulas contained in S. 1132 would have a devastating financial impact on customers in our service area who must ultimately bear the burden of all of the Company's expenses. These individuals are now faced with a potential 27-fold escalation of this charge. This, of course, far exceeds what might be a reasonable escalation when related to the cost of living increase which has occurred since 1925.

Furthermore, FERC on March 31, 1983, instituted a rulemaking with respect to the methodology for the determination of such fees. Preliminary indications are that FERC's proposed methodology would result in an annual fee of $5-6 million. Thus, the long term prospects, if S. 1132 is not enacted, indicate that LG&E customers face the prospect of a further dramatic escalation of their fee when, after the first 10 years of the new license, the protection of the $2.621 million ceiling is removed.

We would like to commend the sponsors for the approach they have taken in S. 1132. It is our feeling that since the amount of the total charge would be determined by the installed capacity and annual generation, it would reflect the value of the project for power production purposes. In addition, the ease of implementation of the formula and its administration would permit cost savings by both licensees and the commission. The predictability and reasonableness of the charge would minimize its inhibitive effect upon new development of hydroelectric power at government dams. Finally, and from LG&E's standpoint, most importantly, the approach you have crafted would provide the government with some increased compensation for the use of its dam (in this case about 3 times what was paid under the initial license) without squeezing from the consumer every last dollar that may be justified on an abstract, theoretical basis.

# # #

The **Chairman**. Thank you again, Senator Melcher, for your appearance.

I appreciate the testimony of each of you today.

There will be some additional questions that may be submitted by the committee in writing for your response in writing.

Mr. **Hough**. Yes.

Ms. **Gibbons**. Yes, sir.

The **Chairman**. The record will remain open for a period of 2 weeks to make the record complete.

Again, thank you very much for your testimony here today. This concludes the hearing. The hearing is now adjourned.

[Whereupon, at 4 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

August 17, 1983

Official Committee File
1983

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 19 1983
WASHINGTON, D.C. 20510

Honorable James A. McClure
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D. C. 20510

Dear Senator McClure:

This is in response to your letter dated August 4, 1983, regarding an amendment to Senate Bill 1132 proposed by Mr. John Baird on behalf of the Columbia Basin Irrigation Districts. This amendment provides that no annual charge shall be assessed in cases in which the United States has heretofore entered into a contract which provides that the licensee may build power plants utilizing irrigation facilities constructed by the United States and shall retain all revenues from such power plants. The Committee requests my views on this amendment, and requests that a list of all non-Federal entities that would be exempted by the amendment be provided to the Committee.

The issues raised by this proposed amendment are the very same issues considered by the Commission in several licensing proceedings involving Columbia Basin Irrigation Districts projects. In its orders in those proceedings, the Commission ruled that notwithstanding the Districts' 1968 contracts, the relevant portion of which is contained in the proposed amendment, the Commission does have the authority to assess Federal Power Act Section 10(e) annual charges for these projects. The Commission stated that nothing in the laws pursuant to which the 1968 contracts were entered into amended or repealed the Federal Power Act so as to limit the Commission's power to impose Section 10(e) annual charges. The Districts have filed applications for rehearing of these orders, and those applications are currently pending before the Commission. Copies of the Commission's orders are enclosed.

I regret that I am unable to provide the Committee with a list of the non-federal entities that would be exempted by this amendment. Except when the issue arises in connection with the licensing of a specific project, contracts between the United States and non-federal entities at federal projects are not provided to the Commission. As a result, I am familiar with the language of a very few of these contracts. The only non-federal entities that I am aware of which would be exempted from paying annual charges under this amendment would be the three Columbia Basin Irrigation Districts. The Army Corps of Engineers and the Bureau of Reclamation may be able to provide the Committee with a more complete list of these entities.

I appreciate the opportunity to present my views on these questions. If I can be of any further assistance to the Committee, please let me know.

Sincerely,

Georgiana Sheldon

Georgiana H. Sheldon
Commissioner

Enclosures

[¶ 61,091]

East Columbia Basin Irrigation District Project Nos. 2849-001 and 3295-000; Quincy-Columbia Basin Irrigation District Project Nos. 2849-001 and 3295-000; South Columbia Basin Irrigation District, Project Nos. 2849-001 and 3295-000

Order Denying Appeals

(Issued November 22, 1982)

Before Commissioners: C. M. Butler III, Chairman; Georgiana Sheldon and Oliver G. Richard III.

The East Columbia Basin Irrigation District, the Quincy-Columbia Basin Irrigation District, and the South Columbia Basin Irrigation District ("Districts") have filed joint appeals of the Director of the Office of Electric Power Regulation's ("Director") August 14, 1981 order issuing a major license to the Districts for Project No. 3295 [16 FERC ¶ 62,243], and the Director's November 16, 1981 order issuing a major license to the Districts for Project No. 2849 [17 FERC ¶ 61,239]. In both these dockets the Cities of Seattle, Washington and Tacoma, Washington ("Cities"), who will purchase the entire output of both projects, have filed motions for leave to intervene out of time (which were granted) and petitions appealing the license orders.

The Districts and the Cities are appealing a portion of one article included in both of the licenses for Project Nos. 2849 and 3295. The appellants object to paragraphs (b) and (c) of Article 33 of both licenses, which require the Districts to pay annual charges to the United States for the use of government lands (paragraph (b)) and for the use of the Main Canal of the Columbia Basin Irrigation Project (paragraph (c)). The appellants contend that the Commission lacks authority to impose these charges or, in the alternative, that the Commission should refrain from imposing these charges. The appellants' claims are grounded generally in the Districts' substantial contributions to the construction, operation and maintenance expenses of the Columbia Basin Project, and specifically in contractual provisions allegedly relieving the Districts from any annual charges. In order to address the appellants' claims, we must first examine the facility under question and the Districts' relationship therewith and with its owners.

Background

Project Nos. 2849 and 3295 are located on the Main Canal of the United States Bureau of Reclamation's ("BOR") Columbia Basin Project, [1] a multipurpose development utilizing a portion of the resources of the Columbia River in the central part of the State of Washington. The Main Canal is a 21 mile irrigation canal located in Grant County, Washington, and is located about 30 miles downstream of the Columbia Basin Project's key feature, the Grand Coulee Dam. *See* Water and Power Resources Service, *Project Data* 375-94 (1980).

In 1945 each of the Districts entered into a contract with the United States, represented by the Secretary of the Interior and BOR, for the construction, operation, and maintenance of the Columbia Basin Project, which provides the Districts with irrigation water for 540,000 acres. Each of the three initial 1945 contracts generally provided that the United States would construct, operate, and maintain the irrigation system included in the Columbia Basin Project. The contracts also provided that the landowners, acting through the Districts, would repay to the United States the cost of operation and maintenance of the irrigation system, plus a contractually agreed upon portion of the cost of constructing the Columbia Basin Project.

In 1968 the Districts and the United States, acting through the Secretary of Interior and BOR, executed three separate amended repayment contracts which superseded the three 1945 repayment contracts. Under the terms of the 1968 contracts the Districts agreed to take over, perform and pay for the operation and maintenance of the irrigation system of the Columbia Basin Project.

One of the changes in the 1968 repayment contracts concerned who could develop and retain the revenue from the development of hydroelectric power at the project. Article 33 of the 1945 contracts had reserved these powers exclusively for the United States. Article 55 of the 1968 contracts, however, provided that either the United States or the Districts (with the Secretary of Interior's approval) may develop hydroelectric power at the site. The contracts further provided that the power facilities and revenues therefrom would be the property of the developer, whether that developer was the United States, a District, or combination of Districts. [2] The Districts center their appeals upon the interpretation of Section 55 of the 1968 repayment contracts.

Commission Authority to Assess Annual Charges

The Districts and the Cities claim that Section 55(b) of the 1968 contract bars the United States, and therefore the Commission, from imposing any annual charge pursuant to Section 10(e) of the Federal Power Act, 16 U.S.C. § 803(e). Under Section 10(e), the Commission is required to fix reasonable annual charges to be paid by licensees for costs of administration and for use of government property. The appellants contend, however, that Section 55(b) represents a clear relinquishment by the United States of any claim it might have under Section 10(e) of the Federal Power Act or any other statute to revenues from such facilities. The Districts state that Section 55(b) of the 1968 repayment contracts provides that the Districts may build hydroelectric generating facilities and that "[a]ll revenues from such [facilities] shall be and remain the property of the Districts." The Districts believe that an analysis of Section 55(a) and 55(b) supports the view that it was the intent of the Districts and the United States to "split the pie" by agreeing that whichever party developed hydroelectric facilities, it would be entitled to all the benefits. A comparison of Section 33 of the initial 1945 repayment contracts with Section 55 of the 1968 contract, in the Districts' view, supports this conclusion of federal relinquishment.

We do not agree with the Districts' arguments. An examination of the Federal Power Act and the reclamation laws will demonstate that the Commission does have the authority to assess Section 10(e) annual charges for these projects, irrespective of the 1968 contracts. [3]

The Columbia Basin Project was initially authorized by Section 2 of the Act of August 30, 1935 (49 Stat. 1028) (the River and Harbors Act). [4] Sections 835 and 835-1 of the Columbia Basin Project Act (57 Stat. 14) (1943) state that the Columbia Basin Project shall be governed by the Federal reclamation laws, including the Act of June 17, 1902 (32 Stat. 388, codified in scattered sections of 43 U.S.C.) and all Acts amendatory thereof or supplementary thereto, and the Reclamation Act of 1939 (53 Stat. 1187). There is no authority in any of the Columbia Basin Project authorizing statutes (or amendments thereto) which would support the view that the BOR may waive Federal Power Act § 10(e) annual charges. We turn, therefore, to the general reclamation laws.

The reclamation laws provide a comprehensive reclamation scheme for the examination and survey of arid and semi-arid Western United States lands and for the construction and maintenance of feasible irrigation works for the storage, diversion and development of water for the reclamation of these lands. See 43 U.S.C. § § 371-573; *Henkel v. United States*, 237 U.S. 43, 49 (1914). Of particular relevance here are Section 5 of the Act of April 16, 1906 and Section 9(c) of the Reclamation Act of 1939, which give the Secretary of the Interior the authority to enter into leases of power privilege for certain BOR projects. 43 U.S.C. § § 522, 485h(c) (1976).

Nothing in these laws, however, conflicts with or permits the waiver of the Commission's authority to impose annual charges for the use of BOR dams. Rather, these provisions of the reclamation laws and Section 10(e) of the Federal Power Act represent separate and distinct legislative schemes. The legislative history of the Federal Power Act reveals no intention to limit the Secretary's authority to grant leases of power privileges under the Act of April 16, 1906. Similarly, nothing in the reclamation laws postdating the Federal Power Act, including the Columbia Basin Project Act, or their respective legislative histories reveals any intent to amend or repeal the Federal Power Act so as to limit the Commission's power to impose Section 10(e) annual charges. Repeals by implication are not favored, *Morton v. Mancari*, 417 U.S. 535 (1974), particularly here, where the implied repeal of Section 10(e) would interfere with a comprehensive regulatory scheme established for the specific purpose of centralizing in one government agency the non-federal development of hydroelectric power. We do not think Congress intended such implied repeals here. Section 10(e), therefore, stands fully applicable to the projects under consideration here.

Congress has not directed that the federal government develop power at the sites for Project Nos. 2849 and 3295. The Commission is thus free to license non-federal development at both projects and impose annual charges, provided that the primary irrigation function of the Columbia Basin Project is not interfered with.

We conclude that neither the Districts' 1968 repayment contracts nor the above cited reclamation laws bar the Commission's assessment of annual charges pursuant to Section 10(e) of the Federal Power Act.

Appropriate Size of Annual Charges

The second major contention of the petitioners is that even if it is concluded that the Commission does have authority to levy annual charges, the Commission should determine that the appropriate charge in both these proceedings should be zero. No charge should be imposed, argue the petitioners, because payments made to the United States pursuant to the 1968 contracts and the performance of the contractual obligations between the Districts and the United States, including the right to use and occupy the Columbia Basin Project irrigation system, have fully repaid the United States for the costs of constructing and maintaining the irrigation system canals. [5]

As was stated in the licenses for Project Nos. 2849 and 3295, the Commission staff is currently reevaluating the methodologies for collection of annual charges under Section 10(e) for use of government property other than lands. Therefore, the license order reserved a final determination of the annual charge for such government property. The Commission's reassessment of its methodologies will include consideration of the equitable arguments raised by the Districts. [6]

The Commission orders:

(A) The petitioners' requests for relief are denied.

— Footnotes —

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[1] Section 3(11) of the Act defines "project" as a complete unit of development. A project may include several developments (each usually consisting of a dam, reservoir, water conduit, powerhouse, and certain transmission facilities) if they are electrically or hydraulically coordinated. *See Pacific Gas and Electric Co.*, 2 FPC 16,529 (1941). The vast Columbia Basin Project is not a project as defined by Section 3(11) of the Federal Power Act. Project Nos 2849 and 3295, however, are projects as thus defined.

[2] The rights granted to the Districts in this area are contained in Article 55(b), which states

> [55(b)]. With prior approval of the Secretary, the District either alone or in conjunction with the other districts, may build plants for the production of power and energy and structures and facilities necessary for the operation of such plants and all such plants shall be and remain in the exclusive control, possession and ownership of the District or districts. ***All revenue from such power-plants and from the use, sale, the disposal of power energy thereinfrom shall be and remain the property of the District or districts.*** [Emphasis added.]

[3] The question of contract interpretation advanced by the Districts is therefore moot.

[4] Section 2 of the River and Harbors Act states in pertinent part:

> *Sec. 2.* That for the purpose of controlling floods, improving navigation, regulating the flow of the streams of the United States, providing for storage and for the delivery of the stored waters thereof, for the reclamation of public lands and Indian reservations, and other beneficial uses, ***and for the generation of electric energy as a means of financially aiding and assisting such undertakings***, the projects known as "Parker Dam" on the Colorado River and "Grand Coulee Dam" on the Columbia River, are hereby authorized and adopted, and all contracts and agreements which have been executed in connection therewith are hereby validated and ratified, and the President, acting through such agents as he may designate, is hereby authorized to construct, operate, and maintain dams, structures, canals, and incidental works necessary to such projects, and in connection therewith to make and enter into any and all necessary contracts including contracts amendatory of or supplemental to those hereby validated and ratified. [Emphasis added.]

[5] The Districts also argue that to impose a zero rental and dam-use charge would be consistent with Commission policy as stated in its Order Issuing License for Project No. 2926, a development which is also located within the Columbia Basin Project, 10 FERC ¶ 61,285 (March 27, 1980). Project No. 2926 was a development which qualified for exemption as a small conduit hydroelectric facility under Section 30 of The Federal Power Act, 16 U.S.C. § 823(a) (added by the Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 3148 (Nov. 9, 1978)). The applicant did not however seek exemption from licensing, only from annual charges under Section 10(e). The Commission granted this limited exemption on the finding that it was consistent with the exemption provisions in that it would encourage development of hydroelectric generating facilities at existing irrigation works. The Commission added that exemption from annual charges was appropriate in that case because the licensee was already paying for a portion of the irrigation system construction costs and for operation and maintenance of the canal. Project No. 2926 is distinguishable from the instant proceedings in that waiver of annual charges was obtained under the exemption provisions of the Act. Additionally, as we note above, the Commission is currently reconsidering its method of computing annual charges

[6] The Districts also argue that the imposition of an annual charge in these two proceedings would cause them economic hardship. The Districts' argument is however premature, since the licenses for Project Nos 2849 and 3295 only provided that any final determinations of annual charges were not to exceed $62,617 for Project No. 2849 and $222,750 for Project No 3295. Both charges are thus subject to downward revision

The Districts contend that because the issues in these proceedings are unique to the Columbia Basin Project, the Commission may grant the relief sought without establishing a policy with regard to other reclamation districts. However, we believe that the issues in these proceedings affect all hydroelectric developments located at federal reclamation projects.

The Commission orders:

The petition for rehearing filed in this docket by the American Falls Reservoir District No. 2 and Big Wood Canal Company is denied.

— Footnotes —

[1] *Cook Electric Company, etal.,* 20 FERC ¶ 62,167 (July 28, 1982).

[2] Petitioners subsequently amended their petition for rehearing to argue, for the first time, that the Big Woods Creek is not a navigable waterway and that the Commission is thus without jurisdiction to issue a license. However, the Commission's licensing jurisdiction extends beyond navigable waterways to streams or bodies of water over which Congress has jurisdiction under its authority to regulate commerce. 16 U.S.C. 797(e)(1976). *See also* 16 U.S.C. 819(b) (1976). Petitioners do not argue that Big Woods Creek is not a stream or body of water over which Congress has jurisdiction.

[3] Although the first *Idaho Renewable* order was issued nearly two months before Petitioners' petition was filed here. Petitioners make no mention of that order.

[4] *See City of Fayetteville Public Works Commission, et al.,* 16 FERC ¶ 61,209 (September 16, 1981).

[5] *Marsh Island Hydro Associates, et al.,* 16 FERC ¶ 61,236 (September 25, 1981). There the Commission issued a permit to the second-in-time applicant which alone had the right to flood its existing hydro project near the proposed sites, thereby demonstrating superior flexibility to maximize the hydro resources at the site.

[6] *City of Ukiah, et al.,* 18 FERC ¶ 61,108 (February 10, 1982) *rehearing denied,* 21 FERC ¶ 61,133 (November 24, 1982). In *Ukiah,* the second-in-time applicant received the permit because it demonstrated that it was the only applicant with legal authority to manipulate the flows from a government dam in such a way as to enhance substantially power production during the early years of the license.

[7] Since Petitioners do not demonstrate that substantially more energy is due to their alleged control and discretion, it is not necessary to reach the question of whether Petitioners' rights are property rights subject to Section 21 of the Act. 16 U.S.C. 815(1976). *See Jack M. Fuls, et al.,* 18 FERC ¶ 61,065 (January 26, 1982). *See also California Department of Water Resources, et al.,* 19 FERC ¶ 61,098 (May 3, 1982).

[¶ 61,312]

East Columbia Basin Irrigation District, Quincy-Columbia Basin Irrigation District and South Columbia Basin Irrigation District, Project No. 2840-003

Order Denying Appeal

(Issued March 17, 1983)

Before Commissioners: C. M. Butler III, Chairman; Georgiana Sheldon, J. David Hughes, A. G. Sousa and Oliver G. Richard III.

The East Columbia Basin Irrigation District, the Quincy-Columbia Basin Irrigation District, and the South Columbia Basin Irrigation District ("Districts") have filed a joint appeal of the Director of the Office of Electric Power Regulation's ("Director") September 21, 1982 order issuing a major license to the Districts for Project No. 2840. [1] Located on the Potholes East Canal in Grant County, Washington, Project No. 2840 utilizes portions of the Columbia Basin Irrigation Project, a multipurpose development located on federal lands managed by the U.S. Bureau of Reclamation ("BOR").

The Districts raise three objections to the Director's order. First, the Districts seek relief from Articles 11 and 33(b) of the license, which provide for certain annual and headwater benefit charges. Second, the Districts seek clarification that project operation must be subordinate to the primary irrigation function of the Columbia Basin Project. Finally, the Districts seek removal of Article 40 of the license, which requires the Districts to develop a fishery mitigation plan.

License Charges

The Districts' first request is that the Commission delete Article 11 and paragraph (b) of Article 33 of the Districts' license. Article 33(b) requires the Districts to pay annual charges to the United States, in an amount to be determined later, for surplus water or water power from a government dam,[2] while Article 11 requires future payment to the Commission for benefits conferred by headwater improvements provided by the United States.[3]

The Districts contend that the Commission lacks authority to impose either of these charges. According to the Districts, such charges are barred by virtually identical "repayment" contracts executed in 1968 between each of the three Districts and the United States Department of the Interior. The Districts rely upon Section 55(b) of each of the three contracts, which states that the Districts shall retain all revenue from any power plants built by the Districts within the Columbia Basin Project. In return for these and other rights, the Districts argue, the Districts agreed to make substantial contributions to the construction, operation, and maintenance expenses of the Columbia Basin Project. The Districts conclude that Articles 11 and 33(b) of the license violate the Districts' contractual rights to all power revenues.

The Districts argue in the alternative that even if the Commission does have authority to levy Section 10(e) annual charges, the Commission should determine that the)appropriate charge for Project No. 2840 is zero (the districts do not extend this argument to the Section 10(f) charges). No charges should be imposed, argue the petitioners, because payments made to the United States pursuant to the 1968 contracts and the performance of the contractual obligations between the Districts and the United States, including the right to use and occupy the Columbia Basin Project irrigation system, have fully repaid the United States for the costs of constructing and maintaining the irrigation system canals. The Districts add that imposition of an annual charge will cause them economic hardship.

Both of these same arguments were made by the Districts in their appeal of the Section 10(e) annual charges included in Director's orders issuing major licenses for Project Nos. 2849 and 3295. [4] We rejected the first argument in that proceeding, and reject it here for the same reason. As we stated in the Order Denying Appeal [5] in that proceeding, neither the Districts' 1968 repayment contracts nor the reclamation laws bar the Commission's assessment of annual charges pursuant to Section 10(e) of the Federal Power Act:

> [T]hese provisions of the reclamation laws and Section 10(e) of the Federal Power Act represent separate and distinct legislative schemes. The legislative history of the Federal Power Act reveals no intention to limit the Secretary [of Interior's] authority to grant leases of power privileges under the Act of April 16, 1906. [43 U.S.C. § 522]. Similarly, nothing in the reclamation laws post-dating the Federal Power Act, including the Columbia Basin Project Act, or their respective legislative histories reveals any intent to amend or repeal the Federal Power Act so as to limit the Commission's power to impose Section 10(e) annual charges.

Our discussion of Section 10(e) of the Act and the reclamation laws in the Project No. 2849 and 3295 proceeding is equally applicable to Section 10(f). The reclamation laws do not limit the Commission's congressionally mandated authority to assess charges for headwater benefits.

With regard to the District's alternative argument—that the appropriate annual charge is zero—we also stated in the Project Nos. 2849 and 3295 proceeding that the Commission was currently reexamining its method of calculating annual charges. We stated that we would defer a final determination of annual charges for Project Nos. 2849 and 3295 until a later date, [6] and that during our reexamination of the issue we would consider the Districts' arguments on this point. We adopt the same approach in this proceeding.

Clarification of License Articles 12 and 13

Article 12 of the license for Project No. 2840 provides that the operations of the Licensee insofar as they affect the use of waters, shall be subject to the Commission's regulations for the protection of life, health and property and to the use of such waters for beneficial public purposes. Article 13 requires the Districts as licensees to permit such reasonable uses of the project as may be ordered by the Commission in the interests of comprehensive development of a waterway for steam-electric, irrigation, municipal, or other similar uses. [7]

The Districts contend that Articles 12 and 13 of the license for Project No. 2840 would reserve to the Commission the authority to direct the operations of the project, and to order the use of project works, lands and waters by persons other than the Districts. The Districts therefore request that the Commission clarify Articles 12 and 13 by adding a special article providing that project operations and incidental uses of project works, lands and waters must be subordinate to the primary irrigation purpose for which the Columbia Basin Project was constructed and is operated.

Clarification of Articles 12 and 13 and the addition of a special article are however unnecessary. Article 39 [8] requires the Districts to enter into an agreement to coordinate their plans with BOR so that the authorized federal purposes of the project site are protected. Activities conducted under Articles 12 and 13 may not conflict with that agreement. Since Article 39 protects the primary irrigation function of the Columbia Basin Project, the Districts' requested article is denied.

Article 40 (Fishery Mitigation)

The Potholes East Canal, from the headworks at O'Sullivan Dam (near the site of Project No. 2840) downstream to Soda Lake, provides a popular sport fishery. The quality of the fishery, however, depends on whether fish survive their passage through the irrigation works at Potholes East Canal Headworks. In an April 14, 1981 letter to the District's consultants [9] the Washington Department of Game ("WDG") recommended as a mitigation measure that the Districts provide funding for replacement fish to be stocked in the canal and Soda Lake. The Director concurred with WDG and in the order issuing license for Project No. 2840, stated that the Districts were obligated to provide mitigation commensurate with the scope of the project. He concluded that negotiated compensation for lost fish measured by replacement cost would be the best form of mitigation for the project. To that end, the license for Project No. 2840 included Article 40, which requires the Districts to develop a fishery mitigation plan based on the replacement cost of project-related losses of fish. [10]

The Districts contend that Article 40 should be deleted as superfluous because the mitigation plan being developed by the Districts pursuant to their license for the upstream Project No. 2849 already addresses mitigation issues for the irrigation system of the Potholes East Canal. Moreover, they contend that operation of Project No. 2840 will have no additional impact on the fishery of the Potholes East Canal because most of the fish that remain in the canal below Potholes Reservoir die when the canal is dewatered each winter.

We believe, however, that a separate fishery mitigation plan for Project No. 2840 is necessary. [11] This is because the fishery affected by Project No. 2840 is distinct from the one affected by Project No. 2849. The distance between Project Nos. 2840 and 2849 is over 25 miles. In addition, two other developments under license to the Districts. Project Nos. 2926 (P.E.C. 22.7) and 3295 (Summer Falls) separate Project No. 2840 from Project No. 2849. The fact that fish entering these waters suffer high mortality rates at the end of the irrigation season does not diminish the waterway's importance as a sport fishery separate from the waters directly affected by Project No. 2849. We will therefore not delete Article 40 from the project license.

The Commission orders:

The petitioners' requests for relief are denied.

— Footnotes —

[1] *East Columbia Irrigation District, et al.*, 20 FERC ¶ 62,505 (September 21, 1982).

[2] Under Section 10(e) of the Federal Power Act ("Act"), 16 U.S.C. § 803(e), the Commission is required to fix reasonable annual charges to be paid by licensees for the use of United States property.

[3] Section 10(f) of the Act, 16 U.S.C. § 803(f), requires the Commission to assess charges against licensees for benefits conferred by storage reservoirs or other headwater improvements constructed by the United States.

[4] *See East Columbia Basin Irrigation District, et al.*, Project No. 3295, 16 FERC ¶ 62,243 (August 14, 1981) and *East Columbia Basin Irrigation District, et al.*, Project No. 2849-001, 17 FERC ¶ 62,239 (November 16, 1981).

[5] *East Columbia Irrigation District et al.*, 21 FERC ¶ 61,091 (November 22, 1982).

[6] The Commission has stated that it will complete a comprehensive review of rulemaking on this subject by the end of 1983. *Louisville Power & Light Co.*, 22 FERC ¶ 61,138 (February 8, 1983).

[7] Articles 12 and 13 of the Districts' license for Project No. 2849 read as follows:

> *Article 12*. The operations of the Licensee, so far as they affect the use, storage and discharge from storage of waters affected by the license, shall at all times be controlled by such reasonable rules and regulations as the Commission may prescribe for the protection of life, health, and property, and in the interest of the fullest, practicable conservation and utilization of such waters for power purposes and for other beneficial public uses, including recreational purposes, and the Licensee shall release water from the project reservoir at such rate in cubic feet per second, or such volume in acre-feet per specified period of time, as the Commission may prescribe for the purposes hereinbefore mentioned.
>
> *Article 13*. On the application of any person, association, corporation, Federal agency, State or municipality, the Licensee shall permit such reasonable use of its reservoir or other project properties, including works, lands and water rights, or parts thereof, as may be ordered by the Commission, after notice and opportunity for hearing, in the interests of comprehensive development of the waterway or waterways involved and the conservation and utilization of the water resources of the region for water supply or for the purposes of steam-electric, irrigation, industrial, municipal or similar uses ***

[8] Article 39 of the Districts license for Project No 2840 reads as follows.

> *Article 39*. The Licensee shall enter into an agreement to coordinate their plans with the U.S. Bureau of Reclamation (BOR) for access to and site activities on lands and property administered by BOR so that the authorized purposes, including operation of the Federal facilities, are protected. In general, the agreement shall not be redundant with the Commission's requirements contained in this license and shall identify the facility, and the study

and construction activities, as applicable, and terms and conditions under which studies and construction will be conducted.

[9] A copy of this letter was included in the Districts' application for license for Project No. 2489 filed on June 4, 1981.

[10] Article 40 of the Districts' license for Project No. 2840 reads in pertinent part as follows:

> *Article 40.* The Licensee shall, in consultation with the Washington Department of Game, the U.S. Bureau of Reclamation, and the U.S. Fish and Wildlife Service, develop a fishery mitigation plan that would include replacement cost of project-related losses of gamefish in Potholes Reservoir, Potholes East Canal, Soda Lake, and Long Lake. Licensee shall, within 1 year from the date of issuance of this license, file for Commission approval the fishery mitigation plan together with comments from the agencies consulted.

[11] To the extent there may be perceived to be an overlap in the studies required for this project and for other projects, the requirements should not be construed to call for duplication of effort by the licensee.

[¶ 61,313]

City of Ogdensburg, New York Project No. 4006-001

Order Dismissing Application for Exemption from Licensing of Small Hydroelectric Project Under 5 MW Capacity

(Issued March 17, 1983)

Before Commissioners: C. M. Butler III, Chairman; Georgiana Sheldon, J. David Hughes, A. G. Sousa and Oliver G. Richard III.

Background

On May 3, 1982, the City of Ogdensburg, New York ("City") filed an application for exemption from licensing [1] for the Ogdensburg Hydroelectric project, FERC Project No. 4006-001. The project would be located on the Oswegatchie River in St. Lawrence County, New York.

By letter of June 8, 1982, the City was notified that its application was deficient because it failed to supply evidence of property ownership or an option to obtain necessary property rights sufficient to develop and operate the project. This information is required under the Commission's regulations, 18 C.F.R. 4.103.

In response, the City filed an amendment to its application, describing its property interests in the site. The City claims to own the lands for the intake, the conduit and the proposed powerhouse, and asserts an ownership interest in certain other properties as well. However, it acknowledges that the dam and some impoundment property rights are held in trust by St. Lawrence County for the owner of certain water rights, and admits that it does not own all of the necessary water rights.

Discussion

The Commission's regulations require an exemption applicant to demonstrate that it has, or has an option to obtain, all the real property interests necessary to develop and operate the project. [2] The City argues that its asserted ability to obtain the remaining necessary water and land rights by its power of condemnation fulfills this requirement. We do not agree. We stated in the preamble to the exemption regulations:

> Possession of state power of eminent domain is not an adequate substitute for ownership of non-Federal lands. The possibilities of bitter and lengthy condemnation litigation before development could go ahead and the 18-month limit on commencing construction portend too great a risk that exemptions in such circumstances would be wasted proceedings.
>
> An entity with state power of eminent domain may, of course, take the necessary interests and then apply for exemption.

Preamble to Exemption Regulations, *FERC Statutes and Regulations* ¶ 30,204, at 31,374 n. 8, 45 Fed. Reg. 76115 (1980). We adhere to that interpretation today, [3] and conclude that the City lacks the necessary property interest (or option to acquire them) required by the exemption regulations and by the underlying policy considerations. Accordingly, we dismiss Ogdensburg's application for exemption. [4]

The Commission orders:

The City of Ogdensburg, New York's application for exemption from licensing filed on May 3, 1982, as amended on July 26, 1982, is dismissed.

— Footnotes —

[1] The application was filed under Section 408 of the Energy Security Act ("Act") of 1980 (16 U.S.C. § § 2705 and 2708 as amended).

[2] 18 C.F.R. § 4.103(b)(2)(ii) (1981). "Real property interests" include water rights. *F.P.C. v. Niagara Mohawk Corp.*, 347 U.S. 239, 248 (1954).

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

Official Committee File

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 19 1983
WASHINGTON, D.C. 20510

Honorable James A. McClure
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

This is an answer to your Committee's questions concerning our testimony on S. 1132.

Senator McClure's Questions

1. Question: What rate of return on investment does the Department consider to be reasonable?

Answer: When the Federal Government allows a non-Federal entity to develop hydroelectric power at an existing Federal dam, it is conferring a benefit upon the non-Federal entity. The value of this benefit varies with development costs, price received for the power produced and the quantity of power produced. The price of the power is affected by supply and demand conditions for electricity and has exhibited an increasing trend over time. The quantity of power produced varies with the flow of the river from one year to the next.

Estimates of this benefit are reflected in benefit/cost ratios which are calculated by dividing the estimated benefits by estimated development costs for potential hydroelectric sites. Benefit/cost ratios range anywhere from zero to positive infinity. Projects with a benefit/cost ratio of less than 1.0 would be deemed infeasible and would not generally be undertaken. The Bureau of Reclamation reports benefit/cost ratios from 1.01 to 6.10 for 57 feasible sites studied in the Western United States (enclosure 1).

This reflects the large differences in value among sites. It would be impossible for a fixed rate to generate a reasonable rate of return on each site when the sites differ so much in value.

A good example of this is obtained by comparing the annual charges that would result from S. 1132 for two very similar projects, Dry Buck in Idaho and Mancos River in New Mexico. The relevant data for this comparison are contained in table S-1 of enclosure 1. Dry Buck on the Payette River would have an installed capacity of 13,050 kilowatts and an average annual generation of 58,330,000 kilowatt hours. The annual charge under S. 1132 would be $42,215 ($29,165 + 13,050). Mancos River on the San Juan River would have an installed capacity of 12,000 kilowatts and an average annual generation of 60,610,000 kilowatt hours. The annual charge under S. 1132 would be $42,305 (30,305 + $12,000). Although the projects sound very similar and the annual charges are almost indentical, the estimated value of the projects is quite different. The benefit/cost ratio for Dry Buck is 2.36 which is more than double the benefit/cost ratio of 1.04 for

Mancos River. The reason for this big difference is the differnce in construction costs for the two projects. Because of the characteristics of the sites, construction costs are estimated at $43,280,000 for Mancos River and only $17,818,000 for Dry Buck. It is differences in the characteristics of the sites owned by the Federal Government rather than any resources or management provided by the developers which account for the differences in value. If a procedure for setting annual charges is to reflect a reasonable rate of return on each site, it must be capable of accounting for the large differences in the value of these sites. As demonstrated above, a flat rate cannot do this.

The market provides the best information of what a reasonable rate of return might be. Even pegging some fixed rate of return on investment would not necessarily reflect a reasonable return. For example, a 6 percent return on investment looked good several years ago but seems rather anemic today. What the market considers a reasonable return changes over time with changing market conditions.

What is needed to reflect a reasonable rate of return for the Federal Government is not a fixed number but a market-based process. If pressed to define a reasonable rate of return, I would say that a reasonable rate of return is what the market says it is. The market determines just what a reasonable rate of return is through the interaction of informed, independent entities in the marketplace.

2. Question: Please describe in detail the Department's methodology for making these calculations.

Answer: As explained above, we feel it is not possible to legislate a number or rate that will generate a reasonable return for the use of Federal resources at all sites in all years. We do feel the use of a market-based process would generate a reasonable return. The process we propose would be a royalty of 5 percent of the power produced at the site and a bonus bid to select the developer of the site. The developer could pay the Federal Government a percentage of the market value of the power or could market the power for the Federal Government. Also, the power could be used by the Government for its own purpose, or it could be marketed by the Federal power marketing agencies.

S. 1132 generates an annual charge by multiplying a fixed dollar value ($1) by a quantity that also is fixed over time, namely the kilowatt hours of installed capacity at a given site, and by multiplying a fixed mill charge (one half mill) by the quantity of energy produced. Although there is some variation in the quantity of energy produced from year to year due to variations in the flow of the river, S. 1132 results in a charge which is relatively constant over time.

The royalty method calculates the annual charge as a fixed percentage of a market value which changes over time, namely the value of the power produced. Market forces may change the value of power over time and this would also change the return to the Government. The royalty method is an improvement over the procedure set forth in S. 1132 because it not only takes account of the variations in quantity produced, as does S. 1132, but also accounts for variations in the value of power. Since the value of the benefit conferred by the Federal Government varies directly with the value of power, the use of the royalty approach, which accounts for this type of variation, is appropriate.

Since it does not reflect differences in cost, the use of the royalty method alone is not sufficient to capture the large differences in value among sites. However, the use of a bonus bid in addition to the royalty could relect these differences in value. The bidding procedure we propose would award the right to develop the site to the highest bidder.

The steps in our proposed bidding process are:

1. The first entity to apply for a permit to study a particular site would be awarded the permit. All information collected during this study would be publicly available.

2. Sealed bids would be submitted with the highest bidder receiving the site. The Federal Energy Regulatory Commission (FERC) would be required to determine if the highest bidder is qualified under current criteria (e.g., financial ability, safety of the project works and operation, environmental factors, suitability of the proposed project to the site, and any other factors deemed to be in the public interest). If the highest bidder is not found to be qualified, the next highest qualified bidder receives the license to develop the site.

   Exceptions are:

   a. A bid by a qualified preference entity would eliminate all non-preference entities from the bidding. There would still be competitive bidding among all interested preference entities.

   b. The permit holder would have two choices if it is not the highest bidder:

      (1) Match the highest bid and be awarded the license. This does not apply if the permit holder is a non-preference entity and the highest bidder is a prefernce entity. OR

      (2) The permit holder can be compensated by the entity receiving the license for the cost of conducting the feasibility study.

The bidding process relies on the market-based cost and revenue estimates of the developer and avoids an administrative determination of the value of a site by the Federal Government. If a site had a high benefit/cost ratio, it would probably attract more than one bidder and the bids would reflect the high site value. With a high profit potential, no developer would be willing to allow another to receive the license for a site for an extremely low bid. Similarly, a site with a low benefit/cost ratio would probably attract very low bonus bids. Even a bonus bid of zero would be acceptable and would reflect a site value very close to the amount represented by the royalty.

Under the bidding procedure, the producer with the most efficient hydroplant design most likely would receive the right to develop the site. This producer could afford to bid more for the site than higher cost producers. Bidding serves as an incentive to the potential licensees to design the lowest cost facility which is consistent with public interest. Competitve bidding would also avoid delays and litigation which have resulted from administrative decisions to award the site to one developer rather than another.

The use of a royalty and competitive bidding has precedent in leasing programs for other federally-owned resources. In most of the sites for other resource leasing programs, the Federal Goverment has used this approach rather than the administrative determination of site value to assure a reasonable return from resourcss that differ significantly in value.

3. Question: What rate of return on investment would S. 1132 provide to the Federal Government? Please provide this information for each Federal dam.

   Answer: There are currently 46 Federal dams, navigation, or irrigation structures where a non-Federal entity is licensed by FERC to produce hydroelectric power. A list of these facilities, the actual annual FERC charge, and the charge under S. 1132 is reported in enclosure 2. Since 1978, the annual charge has either been set as a cap (indicated by $\leq$) or it is stated that it will be determined later. The charges to be determined later are awaiting the outcome of the FERC proposed rulemaking on annual charges. Once the new method for setting annual charges has been decided on, FERC will set annual charges for all of these projects. In a case where a cap is indicated, the annual charge will be no greater than the cap.

   The rate of return on investment is rather difficult to determine since the dollar amount of Federal investment is hard to determine. The Federal Government is allowing the developer to use a site to generate electricity. What the site is worth is probably best reflected by net revenue figures, but such data is difficult to come by for these sites. A good reflection of what the site is worth is what a developer would be willing to pay for it in a competitive bidding situation.

4. Question: Since you do not believe the rates that would be established by S. 1132 are high enough to provide the Government with a reasonable rate of return on its investment, what specific charge per kilowatt of capacity and kilowatt of energy production would provide the Government with a reasonable return on invesment?

Answer: Trying to pin down a flat rate that could be regarded as reasonable is asking the wrong question. The charge that would reflect a reasonable return to the Federal Government differs on a a site-by-site basis. As stated above, the sites differ markedly in value. The best you could hope to do with any flat rate charge is for the charge to be reasonable on the average. The problem with being right on the average, when the individual elements differ greatly in value, is that in some cases the charge will be too high to be reasonable and in other cases, it will be too low.

With an annual charge of zero, any project with a benefit/cost ratio of greater than 1.0 is feasible. As the annual charge is increased, marginal projects (projects with a benefit/cost ratio only slightly greater than 1.0) will be eliminated. An annual charge based on a flat rate leads to a conflict in goals; namely the goal of reasonable return to the government conflicts with the goal of developing additional hydro power. If the flat rate is kept low, not many projects are eliminated, but high valued projects are greatly undercharged. If the flat rate is kept high, there is less of an undercharge of the high valued projects but more projects are eliminated.

Bidding allows the royalty to be set comparatively low because the Government has the assurance that any differences in value pertaining to the site that are not reflected in the uniform royalty will be reflected in the bonus bid.

5. Question: What impact would the higher rate that you would recommend have on electricity prices? Please provide this information for electricity prices for each state.

Answer: First, the process for setting annual charges which we recommend would not result in a higher charge than S. 1132 in all cases. Sometimes it would result in a higher charge and sometimes it would result in a lower charge. It would depend on the value of the site and would vary on a case by case basis.

There are two cases of how annual charges would affect electricity prices. The first case is a small power producer qualified under PURPA to sell power to utilities at cost avoided rates. To qualify, the power producer must have (1) a project of less than 80 megawatts, (2) use a renewable resource in power generation, and (3) not have power production as its main purpose. Such producers have little control over the price received for their power. The small power producer gets the cost avoided rate (or more realistically a negotiated rate somewhat lower than the cost avoided rate) for all units of power that can be produced.

This cost avoided rate is determined by the Public Service Commission in each State and varies from State to State (enclosure 3). Since the producer cannot increase the price and would be foolish to take less, an annual charge will impact solely on producer profits and would not affect electricity price to consumers. Obviously, if an annual charge raised a producer's cost to a level higher than the price received, the producer would cease production. Many of the small hydroelectric facilities that have been developed or that have a permit issued to explore project development fall in this category.

The second case is producers who sell electricity directly to the public. Such producers would have an incentive to bid for a site as long as they could get the electricity for the cost avoided rate or less. They would not be willing to submit a bid that would result in a cost higher than the cost avoided rate as they could always get additional electricity at the cost avoided rate. The annual charge and bonus bid would not cause consumer rates to increase since the maximum that utilities would be willing to bid is their cost avoided rate. They can already obtain additional power at that rate. The effect of the bonus bid and royalty would be to keep consumer rates for electricity from decreasing as much as they might otherwise. Hydropower usually costs much less to produce than the cost avoided rate. Without an annual charge or with a very low annual charge, it is likely that consumer rates would decrease. This is possible because the producer obtains the use of federally-owned resources at below the market rate. Competition in the marketplace would drive the price toward the cost avoided rate, the opportunity cost for that resource. Thus, use of a bonus bid and a royalty would not increase consumer prices for electricity, but would prevent price from decreasing as much as they might in their absence.

6. Question: You note in your testimony that in the past there has been very little hydroelectric development by non-Federal entities at Bureau of Reclamation structures and facilities. Would you not agree that such development is in the national interest?

   Answer: Yes. We feel that hydroelectric development by non-Federal entities at Bureau of Reclamation structures and facilities is in the national interest.

7. Would you also not agree that if the annual charges on these projects are too high, or if there is too much uncertainty as to possible future annual charge obligations, that such development will not take place?

   Answer: Yes. Increased uncertainty and charges that are higher than are warranted by the value of the site would be detrimental to development. As explained in question 4, high charges are warranted for high valued sites and low charges are warranted for low valued sites. The use of a bonus bid and a royalty would give the appropriate results in both cases. This system is site specific and generates a return that is deemed reasonable by the market. The bonus bid and the royalty also create no uncertainty. The developer knows he will have to pay a royalty of 5 percent of the power produced. The developer also knows what he will bid and he will not bid more than he can afford to pay. Both of these charges are known with certainty. The only element of uncertainty is whether the bidder will be the lowest bidder and receive the site. However, the process we propose does address the issue of which producer receives the right to develop the site while S. 1132 is silent on this issue and makes no change in the current first-come-first-served selection process. We believe the highest bidder is a better criteria for selecting who gets the use of Federal resources than first-come-first-served.

8. Question: Would you also not agree that S. 1132 provides developers with certainty as to future charges and that it is sufficiently low so as not to discourage development?

   Answer: S. 1132 does give the developers certainty about the annual charges. Since it is flat rate, it will result in an annual charge which is too low relative to the value of some sites and too high relative to the value of others. It has no means of reflecting the large variations in value among sites. The flat rate in S. 1132 is relatively low and should not discourage development in too many case. However, this will likely result in many of the high valued sites being greatly undercharged.

Answers to Senator Jackson's Questions

1. Question: What would the Department view as a reasonable rate of return?

   Answer: See answer to Senator McClure's first question.

2. Question: In the Department's view, would the proposed FERC rule provide a "reasonable return"?

   Answer: The proposed FERC rule attempts to determine the value of a site on a case-by-case basis. The shared net benefits approach used by FERC can account for the large differences in value among sites and yield on reasonable return to the Government. We have a number of problems with FERC's proposed rulemaking and we addressed these in detail in our comments to FERC (enclosure 4). We feel the market based determination of value which we propose is superior to the administrative determination of value proposed by FERC. Their administrative approach could easily result in charges which were high enough to discourage development in many cases. The FERC approach would also be administratively burdensome to developers and could give developers some serious, initial cash flow problems.

3. Please provide the Committee with amendments to S. 1132 that would, in the Department's view, provide a "reasonable return."

   Answer: These amendments are included as enclosure 5.

4. Question: John Baird, in his written testimony on behalf of the Columbia Basin Irrigation Districts, suggested an amendment that would exempt from charge any licensee that has a contract with the United States which provides that no charge shall be imposed.

(a) Please comment on this proposed amendment.

(b) Please provide the Committee with a list of all non-Federal entities that would be exempted by this amendment.

Answer (4a): We do not oppose any licensee being exempt from a Federal charge that has a contract with the Department of the Interior stating any power potential developed on project facilities would remain in the control of the district and all revenue from such power development and from the use or sale therefrom shall be and remain the property of the district. However, this exemption should be limited to those projects where contracts and agreements specifically identify that power development and revenues will remain the property of the district. We believe other districts should be subject to a falling water charge with consideration being given to the districts' preference standing.

Answer (4b): There are very few entities that have contracts with the Bureau of Reclamation that include an exemption from a Federal charge for the use of Federal facilities. In searching our files, we have found that contracts with the irrigation districts in the Columbia Basin Project (South, East and Quincy) and with the Salt River Valley Water

Users Association in the Salt River Project contain specific language to the effect that any revenues from the sale of power developed by the district would remain the property of the district.

We have contracts with several other irrigation districts that provide for non-Federal power development and the use of the power; however, nothing is mentioned concerning a use charge. These irrigation districts are as follows:

1. Imperial Irrigation District - Boulder Canyon Project
2. Enterprise Irrigation District - Klamath Project, Oregon

I hope these answers to your questions help to clarify our position.

Sincerely,

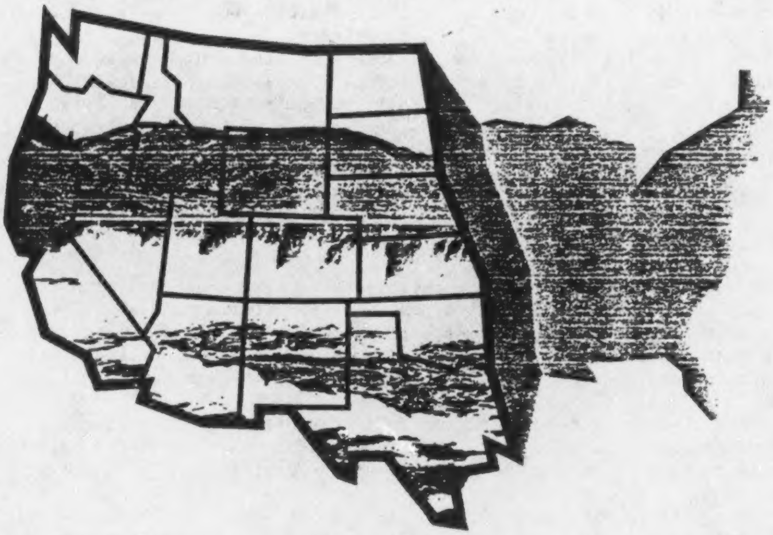
Assistant Secretary - Land and
Water Resources

Enclosures

Enclosure 1

REPORT ON ASSESSMENT OF

LOW-HEAD HYDROELECTRIC SITES
IN THE WESTERN STATES



METHODOLOGY AND SUMMARY

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION

TUDOR ENGINEERING COMPANY
DENVER, COLORADO

MARCH, 1982

PREFACE

This report represents the Third Phase of the Low-Head Hydroelectric Evaluation and Inventory Study. Phase III was conducted by Tudor Engineering Company of San Francisco, California, under contract No. 0-07-DV-00031 with the Bureau of Reclamation. The report consists of site-specific studies for 86 sites including preliminary design, cost estimates, economic analyses, and environmental and social impact assessments.

The purpose of this report is to describe the studies and evaluations on 86 potential hydropower sites selected from Phase II of the study which identified 2,628 sites having hydropower potential. The studies included in this report are in addition to the 159 sites evaluated at existing Reclamation (Bureau of Reclamation) facilities in Phase I of the Low-Head Hydroelectric Evaluation and Inventory. Another purpose of this report is to encourage the development of the low-head hydroelectric development in the Western States by identifying potential sites and providing technical information at each site for use by non-Federal interests.

These studies, while generally equivalent to Reclamation's appraisal level of analysis, were conducted without a normal Reclamation public involvement program. Therefore, environmental and social evaluations should be considered very preliminary indications of potential problem areas and should receive special attention in any future investigations.

This report includes a summary of the Phase III findings as well as a summary of the study methodology. Individual site reports are included in separate appendix volumes by State. Copies of the Summary Report and individual State reports are available from the Chief, Division of Planning Technical Services, Code D-700, Bureau of Reclamation, P.O. Box 25007, Denver, Colorado 80225.

Sheet 1 of 8

TABLE S-1
SUMMARY OF RESULTS
TECHNICAL AND ECONOMIC ANALYSIS

App. No.	Site Number	USBR Region	Site Name and Location	Net Head (Ft)	Installed Capacity (kW)	No. Units	Ave. Ann. Energy (GWh)	Invest. Cost ($1000)	Invest. Cost ($/kW)	Energy Cost M/kWh	B/C Ratio
A-1	CA 2U015	MP	Goodyears Bar North Yuba River	66	4,950	2	16.09	10,457	2,113	51	1.70
A-2	CA 2U027	MP	Mill Creek Kern River	53	3,900	2	10.40	10,311	2,644	78	1.14
A-3	CA 2U028	MP	D'Amico Dam Kern River	66	4,800	2	12.65	10,481	2,184	65	1.36
A-4	CA 2U029	MP	Hamster Dam Kern River	66	4,600	2	12.24	10,744	2,336	69	1.29
A-5	CA 2U036	MP	Lamoine Sacramento River	32	4,070	2	14.27	13,095	3,217	71	1.23
A-6	CA 2U039	MP	Bethstein South Fork American River	66	13,580	2	46.96	31,626	2,329	52	1.70
A-7	CA 2U057	MP	Big Bar Mokelumne River	66	7,920	2	30.41	17,887	2,258	46	1.98
A-8	CA 2U060	MP	Ditch Camp South Fork American River	66	1,980	1	4.85	12,388	6,257	195	.44
A-9	CA 2U061	MP	Esmeralda South Fork American River	66	5,590	1	9.36	11,032	1,974	91	.94
A-10	CO 5U022	UC	Mount Harris Yampa River	9	150	1	1.29	3,987	26,580	251	.25
A-11	CO 5U024	UC	Gore Canyon Colorado River	66	6,840	2	34.19	25,008	3,656	56	1.04
A-12	CO 5U025	UC	Canyon Colorado River	66	6,840	2	34.19	30,341	4,436	67	.86

Sheet 2 of 8

TABLE S-1 (Continued)
SUMMARY OF RESULTS
TECHNICAL AND ECONOMIC ANALYSIS

App. No.	Site Number	USBR Region	Site Name and Location	Net Head (Ft)	Installed Capacity (kW)	No. Units	Ave. Ann. Energy, (GWh)	Invest. Cost ($1000)	Invest. Cost ($/kW)	Energy Cost M/kWh	B/C Ratio
A-13	CO 5UD26	UC	Radium Colorado River	52	6,000	2	30.46	17,048	2,841	43	1.34
A-14	CO 5UD27	UC	Glenwood Canyon Colorado River	13	1,520	1	11.71	7,919	5,210	52	1.19
A-15	CO 5UD28	UC	Storm King Colorado River	20	3,200	1	24.50	9,835	3,089	31	1.97
A-16	CO 5UD29	UC	South Canyon Colorado River	15	2,400	1	18.38	10,076	4,198	42	1.47
A-17	CO 5UD30	UC	Garfield Colorado River	23	3,560	1	25.94	19,685	5,530	58	1.07
A-18	CO 5UD31	UC	Grand Valley Colorado River	24	4,000	1	29.02	15,435	3,859	41	1.51
A-19	CO 5UD32	UC	De Beque Colorado River	24	4,320	1	31.47	16,100	3,727	39	1.58
A-20	CO 5UD34	UC	Sheephorn Blue River	66	1,980	1	12.49	21,189	10,701	128	.45
A-21	CO 5UD38	LM	Americus Arkansas River	32	570	1	3.53	8,614	15,113	189	.31
A-22	CO 5UD39	LM	Elephant Rock Arkansas River	28	510	1	3.15	7,110	13,941	176	.34
A-23	CO 5UD43	UC	Pagosa Junction San Juan	66	2,280	2	11.33	27,003	11,843	179	.31
A-24	ID 4UD01	PN	Kanaka Rapids Snake River	36	25,500	1	161.25	32,199	1,263	16	4.44

Sheet 3 of 8

TABLE S-1 (Continued)
SUMMARY OF RESULTS
TECHNICAL AND ECONOMIC ANALYSIS

App. No.	Site Number	USBR Region	Site Name and Location	Net Head (Ft)	Installed Capacity (kW)	No. Units	Ave. Ann. Energy, (GWh)	Invest. Cost ($1000)	Invest. Cost ($/kW)	Energy Cost M/kWh	B/C Ratio
A-25	ID 4U002	PN	Auger Falls Snake River	66	30,000	2	225.45	30,022	1,001	10	6.54
A-26	ID 4U006	PN	Porter Creek Payette River	24	4,250	2	27.02	13,014	3,062	37	1.69
A-27	ID 4U008	PN	Gardena Payette River	30	10,640	2	51.16	17,709	1,664	27	2.12
A-28	ID 4U009	PN	Dry Buck Payette River	42	13,050	2	58.33	17,818	1,365	24	2.36
A-29	ID 4U011	PN	Tripod Peak North Fork Payette River	19	1,260	1	8.27	5,965	4,734	57	1.11
A-30	ID 4U012	PN	Alpha North Fork Payette River	14	600	1	4.62	5,107	8,511	88	.79
A-31	ID 4U013	UC	Caribou Bear River	66	4,680	2	26.85	24,539	5,243	69	.68
A-32	ID 4U024	PN	Lufkin Bottom Snake River	66	30,000	2	181.2	52,171	1,739	22	2.87
A-33	KS U0093	LM	Edwardsville Kansas River	23	7,500	2	42.46	28,077	3,744	50	1.44
A-34	KS U0095	LM	Lecompton Kansas River	11	1,920	1	14.10	21,302	11,095	114	.73
A-35	KS U0096	LM	Tecumseh Kansas River	8	1,100	1	8.02	13,567	12,334	129	.61
A-36	MT 4U003	PN	Lower Thompson Falls Clark Fork River	9	10,500	1	73.23	34,008	3,239	35	1.66

Sheet 4 of 8

TABLE S-1 (Continued)
SUMMARY OF RESULTS
TECHNICAL AND ECONOMIC ANALYSIS

App. No.	Site Number	USBR Region	Site Name and Location	Net Head (Ft)	Installed Capacity (kW)	No. Units	Ave. Ann. Energy (GWh)	Invest. Cost ($1000)	Invest. Cost ($/kW)	Energy Cost M/kWh	B/C Ratio
A-37	MT 4U004	PN	Tepee Kootenai River	25	27,000	2	134.90	43,767	1,621	25	2.15
A-38	MT 4U007	UM	Lombard Missouri River	10	2,250	1	19.20	14,774	6,566	59	1.07
A-39	MT 4U010	UM	Sentinel Missouri River	9	2,400	1	20.83	12,889	5,370	47	1.34
A-40	MT U0122	UM	Little Porcupine Missouri River	19	10,780	1	60.05	43,185	4,006	54	1.06
A-41	MT U0125	UM	Ulm Missouri River	7	2,220	1	19.49	15,505	6,984	61	1.05
A-42	MT U0150	PN	Alberton Clark River	30	16,500	2	74.71	28,319	1,716	29	1.86
A-43	MT U0174	PN	Swan Lake Swan River	7	180	1	1.60	5,611	31,174	278	.23
A-44	MT U3012	PN	Weeksville Clark Fork River	32	30,000	1	231.58	29,059	969	10	6.10
A-45	MT U3017	PN	Seven Mile Rapids Clark Fork River	48	30,000	2	147.60	32,677	1,089	17	3.19
A-46	MT U3020	PN	Cold Creek Clark Fork River	30	19,500	2	89.59	30,629	1,571	26	2.06
A-47	MT U3022	PN	Superior Clark Fork River	65	30,000	2	156.29	34,443	1,148	17	3.25
A-48	NM 5U006	UC	Archuleta San Juan River	47	4,130	2	21.48	18,643	4,516	66	.86

Sheet 5 of 8

TABLE S-1 (Continued)
SUMMARY OF RESULTS
TECHNICAL AND ECONOMIC ANALYSIS

App. No.	Site Number	USBR Region	Site Name and Location	Net Head (Ft)	Installed Capacity (kW)	No. Units	Ave. Ann. Energy (GWh)	Invest. Cost ($1000)	Invest. Cost ($/kWh)	Energy Cost M/kWh	B/C Ratio
A-49	NM 5U007	UC	Cudai San Juan River	52	9,000	2	44.17	36,785	4,087	63	.89
A-50	NM 5U008	UC	Red Wash San Juan River	42	6,650	2	35.39	39,926	6,004	85	.67
A-51	NM 5U009	UC	Mancos River San Juan River	66	12,000	2	60.61	43,282	3,607	54	1.04
A-52	OK 5U017	SW	Lone Elm Verdigris River	26	12,000	1	26.84	26,416	2,201	76	.67
A-53	OK 5U018	SW	Oologah Verdigris River	22	1,920	1	7.95	10,543	5,491	102	.56
A-54	OK 5U021	SW	Fairfax Arkansas River	33	9,000	2	42.22	45,708	5,079	82	.80
A-55	OK 5U029	SW	Spiro Poteau River	15	550	1	2.60	9,681	17,602	286	.21
A-56	OR 3U006	PN	Lower Opal City Crooked River	66	9,520	1	61.30	14,313	1,503	18	3.50
A-57	OR 3U007	PN	Upper Opal City Crooked River	66	9,520	1	61.30	16,413	1,724	21	3.08
A-58	OR 3U011	PN	Lower Smock Prairie White River	66	1,350	1	9.29	8,974	6,648	75	.81
A-59	OR 3U012	PN	Upper Smock Prairie White River	66	1,350	1	9.29	8,571	6,349	71	.84
A-60	OR 3U013	PN	New Bull Run Bull Run River	61	2,400	1	9.75	9,509	3,962	76	.60

Sheet 6 of 8.

TABLE S-1 (Continued)
SUMMARY OF RESULTS
TECHNICAL AND ECONOMIC ANALYSIS

App. No.	Site Number	USBR Region	Site Name and Location	Net Head (Ft)	Installed Capacity (kW)	No. Units	Ave. Ann. Energy (GWh)	Invest. Cost ($1000)	Invest. Cost ($/kWh)	Energy Cost M/kWh	B/C Ratio
A-61	OR 3U053	PN	Hamner Creek N.Fork Middle Fork Wm.Riv.	66	4,000	2	18.91	13,966	3,491	57	.90
A-62	OR 3U059	PN	Chalk Creek N.Fork Middle Fork Wm.Riv.	29	850	1	5.24	7,165	8,430	107	.52
A-63	OR U0921	PN	Black Canyon Md.Fk.Willamette River	25	4,340	2	28.63	20,730	4,776	55	1.06
A-64	TX 5U002	SW	Threemile Creek Brazos River	35	12,000	2	58.21	27,208	2,267	36	1.65
A-65	TX 5U033	SW	Indian Lake Trinity River	12	880	1	5.55	8,590	9,761	120	0.55
A-66	TX U0028	SW	Garrett's Bluff Red River	23	6,000	2	40.13	36,722	6,120	69	1.03
A-67	TX U0039	SW	Valliant Reservoir Red River	14	3,000	2	22.46	20,139	6,713	68	1.11
A-68	TX U0040	SW	Wade Reservoir Red River	30	19,500	2	76.46	95,060	4,875	93	0.64
A-69	TX U0395	SW	Democrat Crossing Navasota River	10	200	1	0.61	6,415	32,077	823	0.06
A-70	UT 5U005	UC	Sand Knolls Green River	66	30,000	2	155.46	35,028	1,168	18	3.51
A-71	UT 5U010	UC	Hat Martin Colorado River	21	10,500	1	66.28	20,991	1,999	25	2.67
A-72	UT 5U017	UC	Dead Horse Colorado River	35	30,000	2	160.30	37,447	1,248	18	3.50

TABLE S-1 (Continued)
SUMMARY OF RESULTS
TECHNICAL AND ECONOMIC ANALYSIS

Sheet 7 of 8

App. No.	Site Number	USBR Region	Site Name and Location	Net Head (Ft)	Installed Capacity (kW)	No. Units	Ave. Ann. Energy (GWh)	Invest. Cost ($1000)	Invest. Cost ($/kWh)	Energy Cost M/kWh	B/C Ratio
A-73	UT 5U018	UC	Horse Thief Colorado River	14	9,000	1	58.06	28,810	3,201	30	1.74
A-74	UT 5U033	UC	Nine Mile Green River	22	10,500	2	54.20	29,081	2,770	41	1.50
A-75	UT U0051	UC	Slickhorn San Juan River	66	15,000	2	65.65	40,746	2,716	47	1.23
A-76	WA 3U007	PN	Pinnacle Peak White River	50	4,960	1	33.13	11,686	2,356	28	2.16
A-77	WA 3U008	PN	Mud Mountain No. 2 White River	47	4,640	1	31.09	10,812	2,330	27	2.19
A-78	WA 3U009	PN	New Husum White Salmon River	66	4,200	1	28.61	19,033	4,532	51	1.20
A-79	WA 3U023	PN	Brush Creek Wind River	61	6,840	2	33.69	20,759	3,035	47	1.08
A-80	WA 3U046	PN	New Robe So.Fk.Stillaguamish Riv.	59	3,840	2	24.24	9,050	2,357	29	1.94
A-81	WA U0168	PN	Wernick North Fork Nooksack Riv.	59	8,250	2	43.60	24,976	3,027	44	1.28
A-82	WA U0613	PN	McLaughlin Falls Okanogan River	18	1,660	1	12.80	14,351	8,645	85	.74
A-83	WA U0614	PN	Oroville Similkameen River	40	4,300	2	23.48	11,626	2,654	39	1.43
A-84	WY 8U017	UM	Cody Shoshone River	66	6,650	2	34.69	22,062	3,318	49	1.11

TABLE S-1 (Continued)
SUMMARY OF RESULTS
TECHNICAL AND ECONOMIC ANALYSIS

App. No.	Site Number	USBR Region	Site Name and Location	Net Head (Ft)	Installed Capacity (kW)	No. Units	Ave. Ann. Energy (GWh)	Invest. Cost ($1000)	Invest. Cost ($/kW)	Energy Cost M/kWh	B/C Ratio
A-85	WY 8U018	UM	Trotters Station Shoshone River	66	7,210	2	37.73	26,618	3,692	54	1.01
A-86	WY 8U019	UM	Iron Creek Shoshone River	66	7,210	2	37.73	26,686	3,701	54	1.01

TABLE VIII-1 Sheet 1 of 2
ENVIRONMENTAL AND SOCIAL RATINGS
ECONOMIC SITES

Site Number	Site Name	B/C Ratio	Environmental Rating 1/	Social Rating 1/
CA 2U015	Goodyears Bar	1.14	3	1
CA 2U027	Mill Creek	1.14	3	1
CA 2U028	D'Amico Dam	1.36	2	1
CA 2U029	Hamster Dam	1.29	2	1
CA 2U036	Lamoine	1.23	2	1
CA 2U039	Bethstein	1.70	2	3
CA 2U057	Big Bar	1.98	2	2
CO 5U024	Gore Canyon	1.04	2	0
CO 5U026	Radium	1.34	2	1
CO 5U027	Glenwood Canyon	1.19	2	3
CO 5U028	Storm King	1.97	2	3
CO 5U029	South Canyon	1.47	2	3
CO 5U030	Garfield	1.07	1	3
CO 5U031	Grand Valley	1.51	1	0
CO 5U032	De Beque	1.58	2	1
ID 4U001	Kanaka Rapids	4.44	3	1
ID 4U002	Auger Falls	5.32 ←	2	1
ID 4U006	Porter Creek	1.69	1	1
ID 4U008	Gardena	2.12	1	1
ID 4U009	Dry Buck	2.36	1	1
ID 4U011	Tripod Peak	1.11	1	1
ID 4U024	Lufkin Bottom	2.87	3	1
KS U0093	Edwardsville	1.44	0	1
MT 4U003	Lower Thompson Falls	1.66	0	1
MT 4U004	Tepee	2.15	2	1
MT 4U007	Lombard	1.07	1	0
MT 4U010	Sentinel	1.34	1	0
MT 4U122	Little Porcupine	1.06	1	1
MT 4U125	Ulm	1.05	1	2
MT 4U150	Alberton	1.86	2	1
MT U3012	Weeksville	6.10 ←	2	1
MT U3017	Seven Mile Rapids	3.19	2	1
MT U3020	Cold Creek	2.06	2	1
MT U3022	Superior	3.25	2	1
NM 5U009	Mancos River	1.04	2	1
OR 3U006	Lower Opal City	3.32	2	1
OR 3U007	Upper Opal City	2.92	2	1
OR U0921	Black Canyon	1.06	1	0

TABLE VIII-1 (Continued) Sheet 2 f 2
ENVIRONMENTAL AND SOCIAL RATINGS
ECONOMIC SITES

Site Number	Site Name	B/C Rating	Environmental Rating [1]	Social Rating [1]
TX 5U002	Threemile Creek	1.65	1	0
TX U0028	Garrett's Bluff	1.03	0	3
TX U0039	Valliant Reservoir	1.11	0	0
UT 5U005	Sand Knolls	3.51	3	3
UT 5U016	Mat Martin	2.67	3	1
UT 5U017	Dead Horse	3.50	3	3
UT 5U018	Horse Thief	1.74	3	3
UT 5U033	Ninemile	1.50	3	2
UT U0051	Slickhorn	1.23	3	2
WA 3U007	Pinnacle Peak	2.16	1	2
WA 3U008	Mud Mountain No. 2	2.19	2	1
WA 3U009	New Husum	1.15	3	2
WA 3U023	Brush Creek	1.08	3	1
WA 3U046	New Robe	1.94	3	1
WA U0168	Warnick	1.28	3	2
WA U0614	Oroville	1.67	2	2
WY 8U017	Cody	1.11	2	0
WY 8U018	Trotters Station	1.01	0	0
WY 8U019	Iron Creek	1.01←	0	0

[1] Impact Rating Scale:
(0) None, (1) Minor, (2) Moderate, (3) Substantial, (4) Major

Enclosure 2

FERC PROJECT NUMBER	PROJECT NAME	CAPACITY (KW)	AVERAGE ANNUAL PRODUCTION (KWH)	FERC ANNUAL CHARGE	S.1132 ANNUAL CHARGE
2741	Pine Flat	165,000	418,920,000	≤ 1,430,000	374,460
2780	Monticello	11,500	52,000,000	≤ 584,000	37,500
2806	Carlyle	8,750	21,477,000	≤ 36,000	19,489
2816	North Hartland	4,000	18,800,000	determined ltr	13,400
2832	Lucky Peak	75,000	345,000,000	≤ 564,000	247,500
2841	Lake Mendocino	3,500	17,660,000	determined ltr	12,300
2848	Cascade	12,800	49,920,000	≤ 104,350	37,760
2849	Main Canal	18,000	75,900,000	≤ 67,617	55,950
2854	Old River	86,000	750,000,000	determined ltr	461,000
3295	Main Canal	74,000	270,000,000	≤ 222,750	209,000
539	Lock Number 7	2,040	?	4,400	?
2245	Cannelton	70,200	340,000,000	243,700	240,200
2280	Kinzua	451,800	680,826,000	514,000	792,213
2352	Menasha	330	1,755,000	none	1,207.50
2516	Potomac Edison 4	1,000	16,118,000	375	9,059
2517	Potomac Edison 5	1,120	16,600,000	375	9,420
2570	Racine	40,000	222,000,000	50,000	150,000
2588	Little Chute	5,850	19,300,000	none	15,500
2614	Greenup	70,000	300,000,000	227,900	220,000
2677	Badger-Rapide Cr.	8,000	20,500,000	none	18,250
2722	Pineview	5,000	18,300,000	determined ltr	14,150
2736	American Falls	42,400	376,000,000	determined ltr	280,400
2739	Meldahl	70,300	400,000,000	≤ 683,000	270,300
13	Niagara Mohawk	6,000	21,300,000	9,100	16,650
289	Ohio Falls	80,320	374,000,000	95,000	267,320
362	Twin City	14,400	85,600,000	95,440	57,200
1175	Marnet, London	14,400	80,000,000	32,000	54,400
1290	Winfield	14,400	105,500,000	40,000	67,150
1403	Narrows	17,950	136,900,000	not provided	86,400
2056	U.S. Lock & Dam 1	8,000	139,000,000	3,000	77,500
2090	Waterburg 22	5,520	16,000,000	deferred(1954)	13,520
2165	Bankhead	45,500	475,000,000	74,000	282,500
2203	Holt	40,000	166,000,000	67,200	123,000
2211	Markland	64,800	383,000,000	49,950	256,300
2892	Friant	40,000	113,000,000	determined ltr	96,500
3193	Stony George	3,900	16,700,000	determined ltr	12,250
3207	Conemaugh	14,000	39,000,000	determined ltr	33,500
2895	Appleton Upper	900	5,137,000	determined ltr	3,469
2840	O'Sullivan	6,500	19,900,000	determined ltr	16,450
2937	Quincy Chute	7,800	29,230,000	exempted	22,415
2903	New Hogan	2,500	10,110,000	determined ltr	7,555
5124	Wrightsville	1,000	3,000,000	determined ltr	2,500
2888	Whiskeytown	3,240	8,200,000	determined ltr	7,340
3819	Mt. Elbert	2,800	6,477,000	determined ltr	6,039
3253	Campton	250	1,503,000	determined ltr	1,002

Avg. Annual Production - AAP (MWH)

	Project Number	Licensee/Dams	MW	Annual Charge ($)	State	
✓ C	2741 ✓	Kings River ~~Construction~~ Conservation Dist., Ca. Pine Flat AAP 418,920	165.0	≤ 1,430,000	CA	
✓ R	2780 ✓	Solano Irrigation District Monticello AAP= 52,000	11.5	≤ 584,000	CA	
✓ C	2806 ✓	City of Carlyle, Ill. Carlyle AAP= 21,477	8.75	≤ 36,000	IL	
✓ C	2816	Vermont Electric Cooperative North Hartland 18,800	4.0	Determined later	VT	
✓ C	2832 ✓	Boise Project Board - Id. Lucky Peak AAP= 345,000	75.0	≤ 564,000	ID	
✓ C	2841	City of Ukiah, Ca. Lake Mendocino AAP= 17,660	3.5	Determined later ≤ shared net benefits	CA	
✓ R	2848 ✓	Idaho Power Co. Cascade AAP= 49,920	12.8	≤ 104,350	ID	
✓ R	2849 ✓	East-Quincy-South, Wa. Main Canal AAP- 75,900	18.0	≤ 67,617	WA	
✓ C	2854	Town of Vidalia, La. Old River AAP= 750,000	86.0	Determined later	LA	
✓ R	3295	East-Quincy-South, Wa. Main Canal AAP= 270,000	74.0	≤ 222,750	WA	
C	539	Kentucky Utilities Co. Lock No. 7 Hp only - R-14	2.04	4,400	KY	4-1-
✓ C	2245	City of Vanceburg, Ky. Cannelton AAP 340,000	70.2	243,700	KY	3-1-76
✓ C	2280	Penn Elec. Co. - Clev. El. - Ill. Kinzua AAP- 680,826	451.8	514,000	PA	12-1-6
✓ C	2352	George Waiting Paper Co. Menasha 1,755	.33	Not provided for in license 1/	WI	
✓ C	2516	Potomac Edison Co. Potomac Edison #4 AAP= 16,118	1.0	375	WV	2-

1/ Project uses water from U.S. canal. License states no U.S. Dam is affected. No charge was assessed.

C - CORPS OF ENGINEERS
R - BUREAU OF RECLAMATION
F - FOREST SERVICE

ISSUED LICENSES AT GOVERNMENT DAMS AND OTHER FACILITIES

	Project Number	Licensee/Dams	MW	Annual Charge ($)	State	
C	2517	Potomac Edison Co. Potomac Edison #5	1.12	375	WV	12-1-76
C	2570	Ohio Power Co. Racine AAP = 222000	40.0	50,000	OH	12-1-73
C	2588	City of Kaukauna Little Chute	5.85	Not provided for in license 2/	WI	
C	2614	City of Vanceburg, Ky. Greenup AAP = 300,000	70.0	227,900	OH	3-1-76
C	2677	City of Kaukauna Badger-Rapid Croche	8.0	Not provided for in license 2/	WI	
R	2722	Utah Power & Light Pineview AAP = 18,300	5.0	1/	UT	
R	2736	Idaho Power Co. American Falls AAP = 376,000	92.4	1/	ID	
C	2739	City of Vanceburg, Ky. Meldahl AAP = 400,000	70.3	≤ 683,000	KY	
C	13	Niagara Mohawk Pwr. Corp. Niagara Mohawk AAP = 21,300	6.0	9,100	NY	2-1-77
C	289 ✓	Louisville Gas & Elec. Co. Ohio Falls AAP = 374,000	80.32	95,000 94,000 ≤ 4,380,000	KY	6-6-31 [illegible]-1-51
C	362	Ford Motor Co. Twin City AAP = 15,600	14.4	95,440	MN	7-1-50
C	1175	Kanawha Valley Pwr. Co. Marmet	14.4	32,000	WV	1-1-34
C	1175	Kanawha Valley Pwr. Co. London	14.4	32,000	WV	1-1-34
C	1290	Kanawha Valley Pwr. Co. Winfield 15,500	14.4	40,000	WV	4-1-36
C	1403	Pacific Gas & Elec. Co. Narrows AAP = 136,900	17.95	Not provided for in license 3/	CA	5-1-41
C	2056	Northern States Pwr. Co. U.S. Lock & Dam 1 AAP = 139,000	8.0	3,000	MN	9-1-51

1/ License states that payments under BOR contract and reasonable annual charges

2/ Licensee retained rights to use water for power purposes when it sold its interests in project to U.S. (i.e., licensee was prior owner)

3/ No charge pursuant to U.S. Act of 3/1/1893, as amended. (War Department set charges)

	Project Number	Licensee/Dams	MW	Annual Charge ($)	State	
✓ C	2090	Green Mountain Pwr. Corp. Waterburg 22 AAP= 16000	5.52	Deferred in license (1954)	VT	
✓ C	2165	Alabama Power Co. Bankhead AAP= 475,000	45.0	74,000	AL	9-1-57
✓ C	2203	Alabama Power Co. Holt AAP= 166,000	40.0	67,200	AL	10-1-65
✓ C	2211	Public Service Co. of Ind. Markland AAP= 353,200	64.8	49,950	IN	5-1-6
✓ R	2892	Friant Power Authority Friant AAP= 113,000	40.0	Determined later	CA	
✓ C	3193	City of Santa Clara, Ca. Stony George AAP= 16,700	3.9	Determined later	CA	
✓ C	3207	Borough of Saltsburg & Pennsylvania Renewable Res. Conemaugh AAP = 39,000	14.0	Determined later	PA	
✓ C	2895	Kimberly-Clark Corp. Appleton Upper AAP 5,137	.9	Determined later	WI	
✓ R	2840	East-Columbia-Quincy O'Sullivan AAP= 19,900	6.5	Determined later	WA	
✓ R	2937	Quincy-Columbia Quincy Chute AAP= 29,230	7.8	Exempted 1/	WA	
✓ C	2903	Calaneras County Water Dist. New Hogan AAP= 10,110	2.5	Determined later	CA	
✓ C	5124	Montpelier Hydro Electric Co. Wrightsville AAP= 3000	1.0	Determined later	VT	
✓ R	2888	City of Redding Whiskey Town AAP= 8,200	3.24	Determined later	CA	
✓ R	3819	Energenics Systems Mt. Elbert AAP= 6,477	2.8	Determined later	PA	
✓ F	3253	Dole & Robert Sales Corp. Campton AAP= 1,503	.25	Determined later	NH	

1/ Exempted under §30 of FPA. Project qualified as conduit project and received exemption from annual charges.

Enclosure 3

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DOE/NBB-0031
Volume 1 of 2 Volumes

Cogeneration: Regulation, Economics and Capacity

Volume 1: Regulation

April 1983

Prepared for:
Energy Information Administration
Washington, D. C.
Under Contract No. W-7405-Eng-26

Appendix D

Selected Major Utility Price Offers to Qualifying Facilities

State	Major Utility	Energy Price Offer (¢/KWh) On-Peak	Off-Peak	Non-TOD	Period	Comments
Alabama[1]	Alabama Power Company	2.59 2.14	2.17 2.08	2.17 2.08	S W	Standard price offers apply to QF Cogenerators less than 100 KW. Minimum 3-year contract. Prices to other QF's negotiated.
Alaska	Alaska Electric Light and Power Company	Price offers not yet filed.				Utilities required to file by January 14, 1983, standard rates for purchase of non-firm electric power from QFs of less than 100 KW.
Arizona[2]	Arizona Public Service Company	4.60 5.06	2.29 2.52	- -	Non-Firm Power Firm Power	See footnotes for definition of firm and non-firm power. Standard price offers apply to QF cogenerators less than 100 kW.

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[1] Alabama - Alabama Power Company

Winter is November through May   Summer is June through October

A monthly customer charge is also assessed to cover to the cost of metering equipment, meter reading, etc.. The charge is:

	Standard	TOD rate
Single Phase Service	$ 2.81	$14.05 per customer
Three-Phase Service	7.96	17.09

[2] Arizona - Arizona Public Service Company

Firm Power - Power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the agreement from the seller's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the utility's firm power sources.

Non-Firm Power - Electric power which is supplied by the power producer at the producers option where no firm guarantee is provided, and the power can be interrupted by the power producer at any time.

Appendix B

Selected Major Utility Price Offers to Qualifying Facilities (continued)

State	Major Utility	Energy Price Offer (¢/kWh) On-Peak	Off-Peak	Non-TOD	Period	Comments
Arkansas[3]	Arkansas Power and Light Company	4.15 3.39	3.61 3.04	-	S Y	Year-round prices refer to months other than summer. Summer is June-September. Prices for purchases below 7,960 volts and apply to total cogenerated power of less than 5 MW per hour.
California	Pacific Gas and Electric Company	6.05	5.77			Rates given apply to billing months of November, December and January. Partial peak price offer is 5.91¢/kWh.
Colorado[4]	Public Service Company of Colorado	3.50	1.50		Y	Estimated price offers based on utility filings during PURPA hearings.

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[3] Arkansas - Arkansas Power and Light Company

On-Peak/Off-Peak Hours

On-Peak Hours	11:00 a.m. - 9:00 p.m. Monday - Friday	7:00 a.m. - 8:00 p.m. Monday - Friday
Off-Peak Hours	All hours not designated as on-peak hours.	

The avoided energy costs are effective July 1, 1982 and reflect the various losses appropriate to the voltage level at which purchases are made. The voltage level descriptions are Transmission - 115,000 volts or higher; Secondary - lower than 13,800 volts; and Primary - all voltages between Transmission and Secondary. Table 5 prices are for purchases at secondary voltage level.

[4] Colorado - Public Service Company of Colorado

Optional Energy Payment

If a qualifying cogeneration or small power production facility can provide firm power during the normal operation of the Company's diesel-fired generation units, the Company will pay the operating costs avoided by not running its diesel units during the peak periods. This price will be determined on the basis of the cost of fuel at the time of generation.

Capacity Payment

The Company will pay an avoided demand cost to cogenerator or small power producer if it can establish a firm ouput which allows the Company to lower its annual scheduled demand under the Pacific Power and Light purchase contract.

Appendix D

Selected Major Utility Price Offers to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh) On-Peak	Off-Peak	Non-TOD	Period	Comments
Connecticut[5]	Connecticut Light and Power Company	4.99 5.12	3.80 3.93		Non-Firm Power Firm Power	Rates are calculated on average fossil fuel cost for the month of August. Delivery at the secondary distribution level. Line loss CR x Avoid Cost Factor x Fuel Cost = Price
Delaware[6]	Delmarva Power and Light Company	6.37 6.25	3.16 3.73	- -	S W	Monthly metering charge $3.10 Peak Hours - 8:00 a.m. - 9:00 p.m. EST 9:00 a.m. -10:00 p.m. EDST Summer Months: June - September Winter Months: October - May

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[5] Connecticut - Connecticut Light and Power Company

	Secondary distribution Level Line loss Credit	Avoided Cost Factor
Firm Peak	1.087	1.17
Firm Off-Peak	1.06	.92
Non-Firm Peak	1.087	1.14
Non-Firm Off-Peak	1.06	.89

[6] Delaware - Delmarva Power and Light

Summer is June through September Winter is October through May

On peak hours are 8 a.m. to 9 p.m. during periods of the year when Eastern Standard time is in effect, and 9 a.m. to 10 p.m. when Daylight Savings Time is in effect, Monday through Friday, including holidays falling on weekdays. All other hours are off peak hours.

There are metering charges which are handled by the customers at their option, either A or B

	Company pays for Meter	Customer pays for Meter
A) Standard Metering		
Single phase (200 amp)	$ 1.58	$ 0.88
Single phase (400 amp)	3.74	2.07
Three phase (200 amp)	5.61	3.10
Transfomer rated three-phase	17.25	9.55
B) TOD Metering		
Single phase (200 amp)	$ 8.05	$ 4.46
Three phase (200 amp)	10.70	5.97
Transfomer rated three-phase	21.56	11.94

Rates are standard for QFs with a generating capacity of 1,000 kW or less.

Appendix B

Selected Major Utility Price Offers
to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh) On-Peak	 Off-Peak	 Non-TOD	 Period	Comments
Georgia	Savannah Electric Power Company	4.082 2.603	2.969 2.603		Peak Season Off-Peak Season	Based on purchase of 0-25 MW in 1982.
Idaho	Idaho Power Company	- -	- -	6.0 6.6	First 200 kWh all over 200 kWh	Standard price offers apply to QF cogenerators less than 100 kW. Metering charges: Single Phase - $ 5.00 per month Three Phase - $10.00 per month
Illinois	Commonwealth Edison Company	5.35 5.21	2.93 3.10	- -	S W	
Indiana[7]	Public Service Company of Indiana	-	-	1.62	Y	Customer must also pay "excess facilities" charge to compensate company for additional metering equipment
Iowa[8]	Iowa Public Service Company	2.03	1.64	1.82	Y	Monthly Service Charge $7.65

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[7] Indiana - Public Service Company of Indiana

Rate given on Table is only for purchase of energy. Rate for purchase of capacity will be filed by the PSC of Indiana at such time the company can practically defer the purchase of scheduled capacity from another source, or defer acquisition of or delay construction of its own generating facility, or downsize an anticipated future addition to its production plant.

Rates are standard for QFs 100 kW or less, a standard energy rate is available to those QFs having up to a 450 kW generating capacity.

[8] Iowa - Iowa Public Service Company

Capacity Credit

Applicable for generation capacity received only during the on-peak periods defined above.

Capacity credit will be based on current Mid-Continent Area Power Pool (MAPP) Schedule K capacity rates and will be the lesser amount as determined by either Method 1 or Method 2, as follows:

$A = \frac{B}{C} \times D$ where:

Method 1:
A is the capacity credit
B is the kWh delivered during the applicable on-peak period.
C is the number of hours in the applicable on-peak period.
D is the current effective MAPP Schedule K capacity charge adjusted to a monthly basis.

Method 2:
A is the capacity credit.
B is the kWh delivered during the applicable month.
C is the number of hours in the applicable month.
D is the current effective MAPP Schedule K capacity charge adjusted to a monthly basis.

Appendix D

Selected Major Utility Price Offers
to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh) On-Peak	 Off-Peak	 Non-TOD	 Period	Comments
Kansas	Kansas Gas and Electric Company	Flexible Price Structure				Price equal to the total cost of fuel and purchased power expressed in costs per kWh as determined by the monthly energy adjustment clause calculation. Average fuel cost currently 2.0 - 2.5¢ per kWh.
Louisiana	New Orleans Public Service Inc.	3.59 -	3.52 3.09	- -	S W	
Maine[9]	Central Maine Power Company	5.33 5.21	4.97 4.77	5.10 4.92	Y (1-50 MW) Y (50-100 MW)	
Maryland[10]	Baltimore Gas & Electric Company	3.11 2.84	1.41 1.62	- -	S W	Standard prices apply to QF cogenerators with 1000 kW or less.
Massachusetts[11]	Boston Edison Company	6.08-6.45 7.22-7.65	3.93-4.13 4.14-4.35	- -	S W	The purchase price offer is given in a range. The higher price offer is for QFs operating on the 115 kV distribution line and the lower price offer is for the QFs operating on the secondary distribution line. Price offers within the range given as for 14 kV and 4 kV customers.

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[9] Maine - Central Maine Power Company

Rate given on Table is only an interim avoided energy cost rate. Hearings are being held to decide if full avoided costs, with the inclusion of avoided capacity costs, is appropriate.

Those QFs who notify CMP how much generating capacity they will defer before an aggregate sum of deferred CMP generating capacity reaches 50 MW will be offered a higher purchase price offer.

Rates are standard for QFs with a generating capacity of 1,000 kW or less.

[10] Maryland - Baltimore Gas & Electric

Summer is June through September   Winter is October through May

On peak hours are those hours between the hours of 8:00 a.m. and 11:00 p.m., Monday through Friday, and excluding certain National and State holidays.

BG&E installs, owns and maintains at the seller's expense all metering equipment needed to measure the kWh's delivered to the utility.

[11] Massachusetts - Boston Edison Company

The purchase price offer is given in a range. The higher price offer is for QFs operating on the 115 kV distribution line and the lower price offer is for QFs operating on the secondary distribution line. Price offers within the range given are for 14 kV and 4 kV customers.

Appendix D

Selected Major Utility Price Offers to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh) On-Peak	Off-Peak	Non-TOD	Period	Comments
Michigan	Consumers Power Company	5.12	3.50	-	Y	
Minnestota	Northern States Power Company	2.67	1.66	-	S	Price offer available to QF of less than 40 kW capacity who received time-of-day retail electric service.
Missouri[12]	Union Electric Company	2.36	1.47	1.89	S	Weekend and Holiday Prices: Summer - 1.73 Winter - 1.49 Meter Charges: Non-TOD - Single Phase $4.00 per month Three Phase $6.00 per month TOD - Single Phase $13.00 per month - Three Phase $15.00 per month
		2.07	1.52	1.72	W	
Montana	Montana Power Company			2.16	Y short-term	No size requirement for QF. Short-term is minimum of twelve months and less than four years. Long-term is four years or longer. Capacity payment of $5.33/kW is reduced for cogeneration capacity factor less than 85 percent.
				4.50	Y long-term	
Nebraska	Omaha Public Power District	1.60	1.00	1.10	S	Energy accounting charge: kWh or kW meter $1.00 Magnetic tape recorder $2.00 per recorder
		1.20	1.00	1.10	W	

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[12] Missouri - Union Electric Co.

Summer is June through October　　　Winter is November through May

On peak is 10 a.m. - 10 p.m., Monday through Friday
Off peak is 10 p.m. - 10 a.m., Monday through Friday

Appendix D

Selected Major Utility Price Offers
to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/KWh)				Comments
		On-Peak	Off-Peak	Non-TOD	Period	
Nevada[13]	Nevada Power Company	3.01^{A} 2.45^{B} 2.99^{C}	2.33^{A} 1.99^{B} 2.27^{C}	- - -	S W W	
New Hampshire[14]	Public Service Company of New Hampshire	5.7 5.5 5.0	4.6 4.3 4.0		0-20 MW 20-100 MW 100-200 MW	Reflects utility levels of purchase. QF selling 0-20 MW of power receives 5.7¢/KWh for on-peak sales.

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13 Nevada - Nevada Power Company

A - for the month of October, 1982
B - for the month of November, 1982
C - for the month of December, 1982.

On peak for October is 10 a.m. through 10 p.m., daily
Off peak for October is 10 p.m. through 10 a.m., daily

On peak for November and December is 5 a.m. through 10 a.m. and 4 p.m. through 12 midnight.

Off peak for November and December is 12 midnight through 5 a.m. and 10 a.m. through 4 p.m.

Rates given on Table are for energy only. Purchases of capacity are given below. They apply only if the QF has elected to make available (deliver) contract capacity to NPC. The QF must follow certain provisions to qualify for Contract Capacity. Contract Capacity must be available for all of the on peak hours subject to an allowance of ten percent of those on peak hours for forced outages. (Example of one of the provisions.) Capacity payment for October 1982 is $7.65 per kW on-peak, $0.24 per kW off-peak.

The QF is responsible for costs associated with the installation of any metering facilities. These costs are handled under a separate special facilities agreement.

14 New Hampshire - Public Service Co. of New Hampshire

Rates were set by the State Commission and are standard for utilities and small power producers. Final standard rates for cogenerators have not been determined yet.

Appendix D

Selected Major Utility Price Offers to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh) On-Peak	Off-Peak	Non-TOD	Period	Comments
New Jersey[15]	Public Service Electric and Gas Company	8.00	3.70	5.60[I]	S	
		8.14	4.86	6.01[I]	W	
New Mexico[16]	Public Service Company of New Mexico	4.89	2.99	3.47	S	Primary Voltage
		4.95	4.05	3.03	W	Primary Voltage
		5.23	3.23	3.66	S	Secondary Voltage
		5.24	4.33	4.01	W	Secondary Voltage

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15 New Jersey - Public Service Electric and Gas Company

Rate is standard for those QFs with a 1,000 kW generating capacity or less.

I - The summer rate of 5.60 and the Winter rate of 6.01 are intermediate rates not standard all-season rates.

Intermediate is 7 a.m. through 9 p.m. Saturdays
On peak is 7 a.m. through 9 p.m., Mondays through Fridays
Off peak is all other hours.

Summer is June through October   Winter is November through May.

Purchases from a QF will receive a capacity payment when the capacity exceeds 100 kW and the capacity meets certain reliability critera. Capacity payments will be based on the average on peak hours in that month. PSE sets the capacity payment at a rate of $2.56 per kW. The QF may be eligible for an additional payment where the presencne of the QF allows the deferral of local transmission or distribution capacity cost.

Depending on the sophistication of the meter, the QF will be charged between $5.00 and $30.00 per month for installation.

16 New Mexico - Public Service Company of New Mexico

Rates are standard for QFs with a 100 kW generating capacity or less.

The rate for electric energy purchased shall be the energy purchased less test year base fuel cost plus fuel base cost from approved FAC less customer charge any applicable tax.

Summer is June, July, and August   Winter is all other months

A customer charge is billable to the customer and will include but may be limited to, the monthly cost to the company for metering and billing. Below is the applicable schedule.

Customer service charge:

residential	$3.00
small power	$8.00
general power	$20.00
large power	$250.00

For QFs on the TOD rate add an extra $4.00 meter charge.

Appendix D

Selected Major Utility Price Offers to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh)				Comments
		On-Peak	Off-Peak	Non-TOD	Period	
North Carolina	Duke Power Company	3.96	1.94	-	Y	
North Dakota[17]	Montana-Dakota Utilities Company	2.21 -	1.57 -	1.91 1.97-3.08	Y Non-Firm Y Firm	Firm price range reflects term of contract with 5 years at the low end to 30 years at the high end
Ohio	Ohio Power Company					
Oklahoma	Oklahoma Gas and Electric Company	- -	- -	2.362 3.300	Y Y	First price refers to wind power. Second price for hydroelectric and photovoltaic power.
Oregon	Pacific Power and Light Company	2.08 2.08	1.38 1.39	1.60 1.72	Y Non-Firm Y Firm	Capacity price offer of $5.16/kW/Month applies to firm power purchases.

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[17] North Dakota - Montana-Dakota Utilities Co.

Rates are available to QFs with a generating capacity of 100 kW or less.

A QF is considered firm in any month if the QF is delivering power to M-DUC with at least 65% on peak period capacity factor in the month. The capacity factor is based upon maximum on peak demand metered capacity delivered to M-DUC during the month. In addition a firm QF is expected to deliver power at time of M-DUC annual system peak.

On peak is defined as those hours between 8 a.m. and 10 p.m., Monday through Friday.
Off peak is all other hours.

Standard firm energy is based on a 5 to 30 year contract term. Listed below are the corresponding rates and contract terms:

Term	Firm Energy Rate
5 years	1.97 ¢/kWh
10 years	2.16 ¢/kWh
15 years	2.34 ¢/kWh
20 years	2.74 ¢/kWh
25 years	2.93 ¢/kWh
30 years	3.08 ¢/kWh

For non-firm power, meter charges are as follows: Single phase $3.85 per month, three phase $6.00 per month. For firm power, the meter charges are: single phase $5.25 per month and three phase $7.45 per month.

Appendix D

Selected Major Utility Price Offers
to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh)				Comments
		On-Peak	Off-Peak	Non-TOD	Period	
Pennsylvania	Pennsylvania Power and Light Company			6.0	Y Y	Energy output is purchased at the calendar year weighted average value of PP&L's interchange energy sales and purchases when such rate exceeds $0.06 per kWh. Payment on the basis of $0.06 per kWh is made monthly for energy received from the qualifying generating facility in the preceding month with reconciliation with the annual rate as soon as the calendar year data is available.
Rhode Island[18]	Newport Electric Company	5.67	5.26	5.5	Y	
South Carolina[19]	South Carolina Electric and Gas Company	3.27	2.28	-	Y	
South Dakota						
Tennessee	Tennessee Valley Authority	4.649	2.927	3.444	Y	TVA board issued experimental rate UPP-XR under interim guidelines. TVA, on 9/22/82, extended interim guidelines for one-year.

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[18] Rhode Island - Newport Electric Corporation

Rates are handled by NEC on a case-by-case basis.

[19] South Carolina - South Carolina Electric Gas Co.

Rates are standard for QFs with a generating capacity of 100 kW or less.

SCE&GC will pay a QF a monthly capacity credit based on the Monthly Delivered Capacity. Monthly Delivered Capacity shall be the monthly on peak kWh delivered to the utility divided by the total on peak hours in the billing month.

The monthly capacity credit shall be the Monthly Delivered Capacity times the following per kW values

Capacity credit $2.75 per kW

In the billing months of May through November, On peak hours are defined as the hours between 9 a.m. and 11 p.m., Monday through Friday.

In the billing months of December through April, On-peak hours are defined as the hours between 7 a.m. and 10 p.m., Monday through Friday.

Off peak hours are those hours not specified above as on peak hours.

A QF will pay a $4.50 per month seller charge.

Appendix D

Selected Major Utility Price Offers to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh) On-Peak	Off-Peak	Non-TOD	Period	Comments
Utah[20]	Utah Power and Light Company	-	-	2.2 2.6	Y Non-Firm Y Firm	
Vermont[21]	Central Vermont Public Service Corporation	9.00	6.60	7.80	Y	
Virginia[22]	Virginia Electric Power Company	5.28	3.13	-	Y	

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[20] Utah - Utah Power & Light Co.

Rates are standard for QFs with a generating capacity of 1,000 kW or less.

2.2¢ per kWh is offered to QFs who offer energy only.

2.6¢ per kWh is offered if the QF offers power and energy to UP&LC with a contractual guarantee that energy made available in any 12 month period or actually delivered in such period divided by the number of hours in such period is no less than 75% of the contract capacity to allow for forced outages and maintenance.

[21] Vermont - Central Vermont Public Service Co.

Rates have been set by the state commission and are applicable to all QFs.

On peak - 8 a.m. through 8 p.m. Off peak - 8 p.m. through 8 a.m.

[22] Virginia - Virginia Electric Power Co.

On peak hours are 8 a.m. through 11 p.m. Monday through Friday. Off-peak all other hours not listed.

Rates given are for energy payments only. When a QF enters into a contract with VEPCO to provide capacity to VEPCO for a specified term which enables VEPCO to avoid or defer new capacity, capacity additions or firm purchases, VEPCO will pay the QFs a demand credit. Whether the QF is entitled to a demand credit, and how much, is determined by VEPCO based on several provisions.

Appendix D

Selected Major Utility Price Offers to Qualifying Facilities (Continued)

State	Major Utility	Energy Price Offer (¢/kWh) On-Peak	Off-Peak	Non-TOD	Period	Comments
Washington	Washington Water Power Company	-	-	2.7	Y	The rate is standard for QFs with a generating capacity of 100 kW or less. The rate offered is called a generation credit rate in which 2.4¢ kWh is for energy and .3¢ per kWh is for capacity.
West Virginia	Monongahela Power Company					
Wisconsin[23]	Wisconsin Electric Power Company	3.65 3.45 2.90	1.45 1.45 1.45	- - -	S Firm W Firm Y Non-Firm	
Wyoming[24]	Cheyenne Light, Fuel & Power Company	-	-	4.95	Y Non-Firm	

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[23] Wisconsin - Wisconsin Electric Power Company

Rates are standard for QFs except those QFs with a generating capacity over 20 kW may also negotiate their rates.

Summer is July to October   Winter is November to June.

On peak corresponds to the similar hours specified in their customers class of service Time-of-Use rate schedule. Off peak is in a similar fashion.

Rate based on either firm or non-firm power. For those QFs with firm power and Specified Surplus Generating Capacity equal to or in excess of MW, they will not be required to deliver any specified amount of energy, but will stand ready to delivery energy to WEPC by keeping the Specified Surplus Generating Capacity in such control that in may be started and run during 70% of the on peak hours each month for ten months of every year beginning May 1, 1987. During periods of anticipated high demands or system emergencies WEPC, upon giving reasonable notice, may request the customer to deliver the energy from the QF's Specified Surplus Generating Capacity for a period specified by WEPC.

[24] Wyoming -

Rates are standard for QFs with a generating capacity of 100 kW or less.

The standard rate is a non-firm experimental rate based upon Cheyenne Lights wholesale power cost from Pacific Power.

Source: Resource Dynamics Corporation

Enclosure 4

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

ER 83/473

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 1 9 1983
WASHINGTON, D.C. 20510

Honorable Kenneth F. Plumb
Secretary, Federal Energy
  Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

Dear Mr. Plumb:

We have reviewed the proposed changes for determining annual charges for the use of Government dams (docket number RM 83-13-000, 48 FR 15134, April 7, 1983) and have the following comments.

1. Commission perception of the role of the Secretary of the Interior is incorrect.

The Commission notes that § 10(e) of the Federal Power Act of 1920 states that annual charges for reclamation projects are ". . . subject to the approval of the Secretary of the Interior." (page 70). Despite this, the Commission goes on to conclude that ". . . the Commission itself is responsible for determining the annual charges to be paid by licensees." (page 70). The Commission believes (page 71) that the appropriate roles for the Secretary of the Interior are as commentator (on proposed Commission annual charges) or as litigant (in challenging such annual charges).

The Commission bases this conclusion on Montana Power Co. v. FPC, 459 F.2d. 863 (D.C. Cir. 1972). While the Commission admits that this case involves only annual charges for a project on Indian tribal lands, it asserts that the court's interpretation of the "approval clause" of § 10(e) is ". . . equally applicable to projects at Government dams . . ." (page 71, fn. 74).

The Commission offers nothing to substantiate this conclusion. In fact, to assert such a position requires the Commission to expressly ignore the language which Congress enacted. A more reasoned reading of this decision would be that the Secretary is bound by the decision of the Commission if the issue has been appealed to the Commission because the Secretary has been unable either to accept an annual charges offer or to successfully negotiate an agreement. This interpretation finds support in the Court's opinion:

> The Secretary is a public figure who could not insist on withholding approval unless the rental rate to be paid

were unreasonable. Considering the applicable statutes together he may approve a rental offered by the Company, and he may negotiate for an approved consensual arrangement; but if there is no agreement and the matter goes to the Commission, the Secretary can refuse to approve the rate fixed by the Commission only by seeking court review of its determination. As is the situation with the Tribes, the Secretary can participate as a party and avail of the provisions for judicial review (459 F.2d. at 874).

2. Annual charges for Bureau of Reclamation dams.

A Memorandum of Understanding (MOU) presently exists between the Commission and the Bureau of Reclamation (Bureau) regarding Commission approval of the construction of generating facilities at Bureau dams. Unfortunately, the MOU is silent as to the assessment and collection of annual charges, preferring to set the issue aside for study.

At present, annual charges for the use of Bureau dams are collected by the Commission and distributed pursuant to § 17(a) of the Federal Power Act (page 2, fn. 2). This section, now codified at 16 U.S.C. § 810(a), provides:

> All proceeds from any Indian reservation shall be placed to the credit of the Indians of such reservation. All other charges arising from licenses hereunder, except charges fixed by the Commission for the purpose of reimbursing the United States for the costs of administration of this subchapter, shall be paid into the Treasury of the United States, subject to the following distribution: 12 1/2 per centum thereof is hereby appropriated to be paid into the Treasury of the United States and credited to "Miscellaneous receipts;" 50 per centum of the charges arising from licenses hereunder for the occupancy and use of public lands and national forests shall be paid into, reserved, and appropriated as a part of the reclamation fund created by the Act of Congress known as the Reclamation Act, approved June 17, 1902; and 37 1/2 per centum of the charges arising from licenses hereunder for the occupancy and use of national forests and public lands from development within the boundaries of any State shall be paid by the Secretary of the Treasury to such State; and 50 per centum of the charges arising from all other licenses hereunder is reserved and appropriated as a special fund in the Treasury to be expended under the direction of the Secretary of the Army in the maintenance and operation of dams and other navigation structures owned by the United States or in the construction, maintenance, or operation of headwater or other improvements

> of navigable waters of the United States. The proceeds of charges made by the Commission for the purpose of reimbursing the United States for the costs of the administration of this subchapter shall be paid into the Treasury of the United States and credited to miscellaneous receipts.

Since the annual charge for the use of a Bureau dam does not arise from the "occupancy and use of public lands and national forests," none of the revenues produced by the annual charge would be paid into the Reclamation Fund. This occurs despite the fact that Congress has consistently authorized the Bureau to use hydroelectric power revenues to fund the repayment of water development projects. We believe that for projects at Reclamation sites some of the assessment should be paid into the Reclamation Fund.

An alternative to the Commission proposal would be for the Commission to consider a second MOU with the Bureau regarding annual charges. The Secretary of the Interior clearly has authority to assess an annual charge for the use of Bureau dams under § 9(c) of the Reclamation Project Act of 1939. It would appear that the Commission could delegate its duty to the Secretary as long as the general requirements of § 10(e) of the Federal Power Act were met. This approach may be preferable to any new legislation resolving the conflict between the Federal Power Act and the Reclamation Project Act of 1939.

Our primary concern is that the possibility of conflicting authorities between the Federal Power Act and Reclamation Project Act of 1939 should be resolved before establishing a method to determine the amount of the charge.

3. The sharing of net benefits method proposed by the Commission does not reflect the real world of hydroelectric power marketing. Most, if not all, hydroelectric development at Government dams will have a power production capacity of less than 80MW. Because such facilities obviously use a renewable energy resource, they should fall within the definition of "small power production facility" contained in the Public Utility Regulatory Policies Act of 1978 (PURPA). (Pub. L. No. (95-617, § 201, codified at 16 U.S.C. 796 (17)(A).)

Under PURPA, qualifying small-scale power producers are entitled to sell the developer's hydroelectric power to public utilities at a rate equal to the cost the utility avoided by not being required to generate (or purchase) that increment of power. State public utility commissions have promulgated orders defining these "avoided costs" on a utility-specific basis. Avoided cost rates serve as a basis for negotiation between a small-scale hydroelectric developer and a public utility. In large measure, the hydrolectric developers' revenues are defined by the above cost rates.

The method of determining annual charges proposed by the Commission would base such charges on the theoretical value of the power, apparently irrespective of the actual revenues obtained by a small-scale hydroelectric developer from the sale of that power. If the theoretical power value (as defined by the Commission on a regional basis) should happen to be twice the avoided cost rate (as defined by the States on a utility-specific basis) then the small-scale hydroelectric developer could be charged 100 percent of project revenues as an annual charge for using a Government dam. Even this assumes that a hydroelectric developer will obtain the full avoided cost rate from the utility, which is highly unlikely. These cost avoided rates will be reflected in contracts between public utilities and small-scale hydroelectric developers. Because these contracts are generally long term, the Commission assertion (page 33) that actual project revenues will increase with inflation is highly suspect.

4. The Commission procedure will be excessively burdensome on small-scale hydroelectric developers.

The Commission suggests that the generic method proposed to determine power values, powerhouse project costs and net benefits, and to divide those net benefits as an annual charge, ". . . will save the Commission and licensees considerable expenditure of time and resources." (page 72). It is difficult to believe that this is an accurate statement. There is no doubt that access to computing facilities (and computer operators) will be required for a small-scale hydroelectric developer to apply the proposed method to a specific small-scale hydroelectric site. The Commission admits that the process described in footnote 52 (adjusting power value to exclude capacity value for the first 3 years of the project) will require a computer program (page 49, fn. 64). The small-scale hydroelectric developer is also required to use Certified Public Accountants in the reporting of both project costs (pages 36 and 63) and project revenues (page 61) to the Commission. All of these requirements will result in a costly, time-consuming burden on small-scale hydroelectric developers which could result in both increased project costs and increased costs to consumers of hydroelectric project power.

The Commission appears to have erred in certifying that the proposed rule, if promulgated, will not have a "significant economic impact on a substantial number of small entities." (page 80). This finding, which allowed the Commission to avoid the requirements of the Regulatory Flexibility Act of 1980 (RFA), was based on three considerations: (1) that the economic impact of the rule was ". . . not likely to be significant" (page 79); (2) that the number of permit and license applicants wishing to use Government dams (158 existing and pending) was not significant (page 79); and (3) that ". . . many hydroelectric developers do not fall within the RFA's definition of small entity." (page 78).

The substantial economic impact of the proposed rule on small-scale hydroelectric developers is fairly clear. Standing alone, the number of permit and license applicants wishing to use Government dams would not appear to justify an RFA exemption. Finally the Commission's determination that most hydroelectric developers do not fall within the definition of "small-business concern" contained in the Small Business Act is neither consistent with the language of the Act nor with the regulations promulgated by the Small Business Administration to implement the Act (13 C.F.R. § 121.3-1). One of the statutory considerations in defining a small-business concern, for example, is the requirement that the business not be ". . . dominant in its field of operation." (15 U.S.C. § 632). This is important in light of the PURPA requirement that a "qualifying small power production facility be owned by . . . a person not primarily engaged in the generation or sale of electric power." (16 U.S.C. § 796(17)(C)(ii)). There can be little doubt that most, if not all, small-scale hydroelectric developers are small-business concerns within the meaning of both the Small Business Act and the Regulatory Flexibility Act of 1980.

5. The proposed rulemaking is too complex. This would affect both the Commission and potential developers of hydro sites. From the Commission's standpoint, the proposed rule would result in a large data collection effort and heavy administrative burden. Significant staff time would be required to compile the necessary data and to calculate the regional power values. Additional time would be necessary to make all of the necessary calculations for each project and to check compliance on actual project costs.

This appears to be inconsistent with this Administration's policy to reduce the size of the Federal Government. The State public utility commissions are better able to determine the value of a small-scale hydroelectric developers' power, and the avoided cost rates that will determine the developers revenue, than is the Commission. Any expansion of the Commission role that will have the effect of duplicating existing expertise at the State level is unnecessary.

Although a generic approach is sought, most of the necessary computations are still on a case-by-case basis. With approximately 1,800 preliminary applications filed with the Commission in 1981, a method of setting annual charges is needed which would reduce the time and resources now required to fix annual charges under the case-by-case approach.

From the potential developer's standpoint, the proposed rule would almost ensure that a consultant would need to be retained to perform the calculations. The proposed rule would take more expertise on the part of developers in the preliminary stages of development than is currently the case. This would tend to discourage the development of small hydro sites.

Both money and administrative burden could be saved by adopting a simpler rule for setting annual charges for the use of Government dams.

6. The use of actual project costs in determining the net benefit would mean that the actual annual charge would not be known to the developer until after the project was completed. Currently, the actual annual charge is determined during the licensing procedure and is known by the developer before project construction begins. This delay in determining actual annual charge under the proposed rulemaking would seem to add an element of uncertainty to the process that does not currently exist. Increasing uncertainty would tend to discourage the development of hydro power. The procedure should rely on estimated cost rather than actual cost. These costs should be fairly well known at the time of project licensing. Allowing a developer to base the charge on estimated cost allows the developer to pay only 50 percent of his cost. This removes one half of the incentive for a developer to save on cost once his project has been approved. Furthermore, the method proposed by FERC would greatly increase the regulatory burden upon developers in submitting detailed cost information.

7. Alternatives were not fully explored and were dismissed rather quickly in Section VI of the proposed rulemaking. Several alternatives to the proposed rulemaking are:

    a. A royalty method where the Government has claim to some fixed percentage of the power produced by the project. This is similar to the method used in oil and gas leases. The power could be used by the Government for its own purposes or marketed by the Federal power marketing agencies to generate revenue. This alternative would be easy to calculate, certain, and would lower the administrative burden both on FERC and potential developers. Returns to the Government would also keep pace with any increases in power rates. Although royalties could also be expressed as a percentage of gross revenues, expressing royalties as a percentage of the power produced covers situations in which the power is sold to another party (revenues produced) and situations in which the producer uses the power for other project purposes (no revenues produced, ex: irrigation district).

    b. A flat charge per KWH of installed capacity and a charge per KWH of power produced. This is similar to S. 1132 introduced by Senator McClure. This could be indexed to either a national or regional rate index to keep pace with any increases in power rates. This would also be easy to calculate and simple to administer.

These and other alternatives are more fully explored in a paper enclosed as Appendix A.

8. Indexing annual charges to the GNP deflator is inappropriate for two reasons.

First, this could have a very damaging effect on small-scale hydroelectric development since project revenues are a function of a utility's avoided costs. If the utility's avoided costs decline, perhaps through the construction of additional generating capacity or through a reduction in the demand for electricity, then the small-scale hydroelectric developers' revenues are likely to decline as well. This decline could occur regardless of the Gross National Product.

Secondly, one of the real benefits of hydropower energy is its inherent freedom from the effects of inflation. Normally, the major portion of annual cost in hydropower generation is for repayment of investment costs. Once the financing is established, the only cost of generation that can be affected by inflation or deflation is the operation and maintenance (O&M) cost. Therefore, the rate of change in the actual total annual cost of production is much less than the rate of inflation or deflation occurring.

The following example is used to demonstrate the effect of inflation and deflation. To simplify the example, we have assumed that revenues from energy sales increase or decrease at the same rate as the GNP index although, as we have stated, we believe it is not appropriate.

	First Year	40 Percent Increase	10 Percent Decrease
Annual Gross Revenue	$670,000	$938,000	$603,000
Annual Cost 1/	570,000	615,600	558,600
Net Revenues Before Annual Charge	100,000	322,400	44,400
Annual Charge	50,000	70,000	45,000
Net After Annual Charge	$ 50,000	$252,400	$ - 600

1/ Assumes that 80 percent of annual cost is for repayment of investment (fixed or sunk costs and not subject to inflation) and 20 percent is for O&M (variable costs and is subject to inflation). Thus, inflation only affects 20 percent of the annual cost. The annual cost for a 40 percent increase is calculated as 570,000 + (.4)(.2) 570,000 = 615,600.

If the premise for assessing an annual use charge is "equal sharing of benefits," the method for establishing the charge must account for the stable annual costs of hydropower; otherwise, there will not be equal sharing. The proposed method does not do so because it would be more applicable to thermal fired powerplants where the larger portion of annual costs is for O&M, primarily the cost of fuel.

9. If some method of indexing is used, the use of the GNP Deflator to adjust the annual payment amount for inflation may not be the most appropriate index. It seems that an index more specific to trends in power rates would be better for indexing benefits than an inflation indicator for the national economy as a whole. Perhaps an index specific to each region could be computed by FERC which is based on the wholesale market price of energy. Of course, the real fuel escalation factor should be calibrated to this index before using it in benefit calculation.

10. Basing estimated benefits on estimated regional power values can be a real problem. This approach will work well only if the rate structures faced by projects within a region are fairly homogeneous. This forces a tradeoff between homogeneity and the sizing of the regions. The larger the regions, the greater is the likelihood that they will lack homogeneity. The smaller the regions, the greater will be the administrative burden in calculating regional power values.

11. In Section VIII dealing with environmental impacts, the statement is made that "The rule does not itself affect the decision to construct a project." We disagree with this statement. To encourage hydro development the annual charges need to be (1) easy to calculate, (2) certain, and (3) as low as possible consistent with other objectives. They must be easy to calculate to aid potential developers in financial analysis of the project. They must be certain because increased uncertainty hampers hydro development.

    The proposed rulemaking misses on all three counts. It would have the impact of making the annual charge harder to calculate, of being more uncertain (because it is determined after the completion of the project and it is indexed to GNP), and of resulting in higher annual charges than the current process.

12. There appears to be an inconsistency in the New England example on pages 51 and 52. In this example, the combined value of capacity and firm energy for every combination of capacity and peak season capacity factors was lower than the value of the system lambda, the fuel savings associated wth non-firm alternatives. For the particular combination of capacity factors for which a detailed presentation was made, the combined value of firm capacity and firm energy was 4.61 cents/KWH, compared to 4.65 cents/KWH for non-firm energy.

13. Page 40. Another inconsistency occurs in the use of a value for cost of capital different from interest during construction. They should be used in a consistent manner.

14. Pages 23 and 49. We feel that the formula used to determine the capacity value part of the benefits might be in error. The peak season capacity factor (PSCF) used to adjust the value should be replaced by the hydrologic availability factor which will give the hydroplants' derated capacity. The PSCF bears no relation to the amount of dependable capacity available in the system. It is simply a reflection of the amount of time the unit was placed in service during the peak season.

15. Page 29. We disagree with the notion that the hydroplant's firm energy cannot exceed that of the thermal alternative, and that any hydrogeneration in excess of the thermal generation must be evaluated without a capacity component. When there is adequate flow and/or storage, hydropower should be considered as firm. To claim the additional generation as non-firm could significantly understate the value of the hydropower addition.

16. Page 49. We feel that the 3-year delay in claiming capacity benefits is not necessary and adds needless complexity. In most cases, the private companies applying for these licenses have enough of a planning horizon (anywhere from 5-15 years) to integrate the hydrounit into their normal expansion plans and thereby reduce the chance of duplication of capacity additions. Even if a company has a 20 percent reserve margin at the time of license application, this could probably change significantly by the time the plant comes on-line.

17. Page 30. There seems to be inadequate consideration given to low-head hydroplants which are located on dams or canals where water releases are under complete control of irrigation districts. Under these conditions, the irrigation districts may shut down all water releases at any time depending on their requirements. The capacity of the new hydroplant will do nothing to reduce the capacity charges from the primary power supply and cannot have a true capacity value. Thus, great care must be exercised in projecting availability during peak periods. In order to determine the annual value of power as defined in paragraph III.A.1.(1), the annual generation would have to be known. In some areas, particularly the southwest, there have been periods of 10 consecutive years when 30 percent or less of the average annual water supply was available for releases. Accurate projection of the amount of generation, even over a long period of time, will also be difficult under these conditions.

18. Page 20. Changing the formula for small projects is risky in that it could encourage developers to undersize the project to avoid a higher charge. Deferral of collections on smaller projects might be preferred to charging a smaller share of net benefits. However, a charge based on actual production would avoid the cash flow problems associated with the net benefits rule.

19. Page 40. With regard to costs, we feel that the construction costs used in the examples for the thermal alternatives were excessively low (about half of what they currently should be). They seem to be based

on old data (1975) and cannot be compared to the current, private construction costs for the hydropower. If prospective evaluations are to have any valid economic significance, all benefits and costs should be measured in a common time frame.

20. The Commission asserts that "Licensees will directly benefit from the elimination of the litigation burden that has, at times, accompanied the setting of annual charges for a project." (page 8). There is no way that the Commission can make such an assertion. In fact, the complexity of the proposed method to be used to determine annual charges could result in increased litigation.

21. The Commission should require that the total cost of mitigation for negative impacts to fish and wildlife resources be fully factored into the calculation of project costs.

22. In setting annual charges for the use of Federal dams, several objectives must be considered. Charges must be set so that (1) the Federal Government obtains a reasonable return for the use of public resources, (2) the price of power to consumers is not increased, and (3) the development of hydro power is encouraged. Clearly, some of these objectives are conflicting and tradeoffs must be made in establishing a process for determining actual annual charges. The higher the annual charge, the greater is the return to the Federal Government. However, higher annual charges are passed through to consumers in the form of higher prices through the rate making process. Also, higher annual charges tend to discourage the development of hydro power. The Commission needs to address this in the proposed rulemaking. From the discussion of alternatives in Section VI, it seems as though the Commission is placing primary importance on return to the Government. I am not certain that Congress would agree with this priority. As most recently expressed in PURPA, Congress seems to place the highest priority on the development of hydro power and keeping cost to consumers low.

23. We recommend that the annual charge for use of Federal hydroelectric sites be determined using the royalty method. Specifically, the annual charges should be set at 5 percent of the power produced. This would be equivalent to 5 percent of gross revenues in most cases. Further, we recommend that the developer of the site be selected using a bonus bid with the highest bidder receiving the license to develop the site.

Bidding the site would ensure that the lowest cost producer received the site, would hold power rates down, would extract some of the economic rent pertaining to a site, and would make the process of selecting the developer compatible with the procedures used in leasing other federally-owned resources. Given the importance of selecting the best developer for the limited number of Federal sites and of the size of the Federal revenues involved, we believe that the changes in legislation necessary to make a bidding procedure workable are warranted.

We believe we have outlined a workable bidding procedure in the enclosed paper which adequately addresses the preference provisions of the Federal Power Act. The statutory change needed to make this bidding procedure workable is to eliminate the wording in Section 5 of the Federal Power Act which gives the permittee priority of application for a license. We feel that giving the permittee the right of first refusal in the bidding process or allowing for compensation for studying the site is sufficient advantage to the permittee.

If the shared net benefits approach is used, we recommend a much simpler method that:

(a) uses actual avoided cost or contract rates as the measure of benefits;

(b) uses estimated project costs rather than actual project costs; and,

(c) more carefully addresses the indexing problem.

Sincerely,

J.J. Simmons III
UNDER SECRETARY

Assistant Secretary - Land and
Water Resources

Enclosure

ALTERNATIVES FOR DETERMINING ANNUAL CHARGES

FOR THE USE OF FEDERAL HYDROPOWER SITES

SUMMARY

The Secretary of the Interior has primary authority over the hydropower development of a site when this is authorized by Congress as a project feature. In these cases, the Secretary may establish a power privilege charge. Where Congress has not expressly authorized Federal hydropower development, a non-Federal entity may develop the site. Under Section 10e of the Federal Power Act, the Federal Energy Regulatory Commission (FERC) is charged with setting reasonable annual charges for the use of Federal hydroelectric sites by non-Federal entities. This paper examines alternatives for calculating this annual charge.

Alternatives are evaluated using the following criteria: (1) economic efficiency, (2) return to the Federal Treasury, (3) administrative efficiency, (4) removal of uncertainty, and (5) acceptability to the power industry. Because of the nature of the demand and marginal cost curves, there is little difference in economic efficiency among the alternatives for setting annual charges. The major differences among alternatives are based on the other four criteria.

The alternatives examined in this paper are:

1. Fifty percent of regionalized net benefits. This alternative is currently being proposed by FERC as a change in the regulations for determining annual charges. It is a four step approach which involves: (1) determining on a regional basis the annual cost of power from the least expensive alternative power source (power value) and using this as the measure of benefits; (b) determining the annual cost of hydroelectric project power (project powerhouse costs) using actual project construction costs; (c) determining net benefits by subtracting powerhouse costs from power benefits; and (d) charging the licensee 50 percent of the levelized net benefits for the privilege of developing hydroelectric power at a Government dam or other structure.

2. Flat rate charge. This alternative would charge a fixed dollar amount per kilowatt of installed capacity and a fixed mil amount per kilowatt hour of power produced. This is the approach suggested in S. 1132 which proposes an annual charge of $1 per kilowatt of installed capacity and one-half mil per kilowatt hour of energy produced.

3. Percentage of net revenues. This alternative would base the annual charge on a fixed percentage of the actual net revenues accruing to the developer of a site.

4. Percentage of gross revenues. This alternative would base the annual charge on a fixed percentage of actual gross revenues accruing to the developer of a site.

5. Percentage of the power produced (royalty). This alternative would make the annual charge some fixed percentage of the power produced

by the project, similar to the method used in oil and gas leases. The power could be used by the Government for its own purposes, marketed by the Federal power marketing agencies, or marketed by the developer for the Federal Government.

It is recommended that annual charges be determined using the royalty method. The royalty method is conceptually the same as the percentage of gross revenues method (alternative 4) and would cover not only projects where revenue is produced, but also projects in which the developer uses the power for other project purposes, such as irrigation districts, and no revenue is produced.

Alternative 1 is not desirable because it is much more complex than the other alternatives and charges are difficult to calculate. It would not only increase the administrative burden, but would also increase the uncertainty to developers over the present method of assessing annual charges. Initial indications are that this alternative is viewed as very unfavorable by the power industry. The returns to the Treasury under this alternative would probably be higher than for any of the other alternatives.

Alternative 2 is the most acceptable to the power industry. It is easy to calculate and use in any feasibility analysis and would be very easy to administer. Returns to the Treasury would probably not be as great as using alternative 1. The Government would not share in any increases in power rates and the developer could be excessively burdened by any decrease in power rates.

Alternative 3 would entail a large annual administrative burden for FERC in the form of compliance checks probably resulting in larger administrative costs than any other option. This alternative would also weaken the incentive to control costs. Returns could be approximately equal to the returns under alternative 1 over the life of the project. For example, if the percentage were fixed at 50 percent of net revenues, this should be approximately equal to 50 percent of net benefits. The Government would share in any increases or decreases in the value of electricity. Annual charges would be based on actual rather than estimated data. This alternative is not viewed favorably by the power industry.

The alternatives for setting the annual charge considered in this paper do not ensure that the lowest cost producer receives the site. FERC issues the permit to study the site on a first-come-first-served basis. The permittee has first priority at the license stage if the permittee's plan is equally well adapted to the site. It is recommended that site selection be determined using a bonus bid with the highest bidder receiving the license to develop the site. Because the permittee has priority at the license stage, this bidding scheme for site selection is contrary to existing statutes. It would take a statutory change to permit this type of bidding. Bidding the site would ensure that the lowest cost producer received the site, would extract some of the economic rent pertaining to a site, and would make the process of selecting the developer compatible with the procedures used in leasing other federally-owned resources.

I. Introduction

The purpose of the Federal Energy Regulatory Commission (FERC) Rulemaking (RM83-13-000) is to amend the regulations governing annual charges for hydroelectric power projects that use Federal sites. It proposes to switch from a case-by-case calculation of annual charges to a generic formula-based approach. Although a generic approach is sought, many of the necessary computations are still on a case-by-case basis. It would continue FERC's procedure of assessing a charge equal to one half of the net benefits (project benefits less costs), but would switch from a determination of benefits based on site-specific power values and an estimate of costs to a formula-based calculation of benefits and to actual project costs. Benefits under this proposal would still be calculated on a case-by-case basis, but using formulas which are based on regional power values. The annual charge would be adjusted annually for inflation using the Gross National Product deflator. This charge would apply to power producers at Federal sites where power is not an authorized purpose. Included are projects to be licensed in the future, recently licensed projects with license fees yet to be determined, and adjustments of annual charges. Payments by project sponsors to the Bureau of Reclamation for lease of power privilege or repayment obligations would not be credited against this charge nor would any portion of the revenue received by FERC be allocated to the Reclamation Fund.

FERC contends that the proposed rule will avoid increased costs to consumers of electric power, reduce the time and resources expended by FERC and its licensees to calculate the annual charge, and expedite the licensing process. The proposed rule does not affect the process used by FERC to determine which non-Federal entity is selected to develop the site.

In this paper several alternative procedures for assessing the charge for the use of Federal sites are evaluated and two procedures are recommended for consideration, bidding the site and payment of a royalty. Bidding the site would also change the process by which the licensee is selected. Bidding the site and payment of a royalty would be similar to the procedure that is currently used in gas, oil, and coal leasing. Interior believes that these market-oriented alternatives will be economically efficient, fair to consumers and potential licensees, and less burdensome to administer than either the FERC proposed rulemaking or the current FERC permitting process. However, a change in the Federal Power Act would be necessary to allow bidding for the license.

II. Background

The Secretary of the Interior has primary authority over the hydropower development of a site when hydropower is expressly authorized by Congress (18 CFR 4.30). In those cases where he has development authority, the Secretary may establish a power privilege charge (section 9(c) of Reclamation Project Act of 1939, 43 U.S.C. 485h (c)).

In cases where Congress has not authorized Federal hydropower development at a site, a non-Federal entity may develop the site (section 4(c) and 23(b) of the Federal Power Act, 16 U.S.C. §§ 797(e), 817(b)). FERC determines which non-Federal entity is issued the permit to study the site, which entity is issued the license to develop the site, and establishes a license fee (section 10(e) of the Federal Power Act).

When the site at issue involves the use of a Bureau facility, the Secretary can assess a power privilege charge in addition to FERC's annual charge. Furthermore, FERC must obtain approval of its charge from the Secretary. Outside of requiring that the FERC license contain conditions necessary for adequate protection and utilization of the project, the Secretary has no input on selection of permittees and licensees. The process is determined by FERC.

The Federal Power Acts gives FERC the authority to issue licenses to citizens of the United States for the purpose of constructing, operating, and maintaining dams, conduits, transmission lines, and powerhouses in any of the streams or other bodies of water over which Congress has jurisdiction to regulate commerce, including surplus water or water power from any Government dam. FERC also has the authority to issue preliminary permits for the purpose of enabling applicants for a license to secure the data to prepare maps, plans, specifications, and estimates of cost as may be required for a full understanding of the proposed project. Each permit issued shall be for the sole purpose of investigating the development potential of a site. The permit also maintains priority of application for a license for a period not exceeding 3 years. It is not necessary to have a permit before applying for a license.

Even though one entity has received a permit to study a particular site, another entity may file for a license to develop that site. However, the Federal Power Act requires that the license be issued to the permit holder as long as the permittee's plans are equally well adapted to develop the site or will be made equally well adapted. Due to the permittee's priority right, the permittee would also have priority over a preference entity at this stage of the licensing process.

Preference will be given to States, municipalities, and other public entities in issuing permits as provided in the Federal Power Act and for licenses where no permit has been issued. However, States, municipalities, and other public entities do not have preference over a permittee as long as the permittee's plan is equally well adapted to the specific site. Preference to the site granted to States, municipalities, and other public entities under the Federal Power Act should not be confused with the preference that these public entities have to power produced by the Federal Government under the Reclamation Project Act.

Thus, it appears that a bidding process could not be utilized at the licensing stage since the permittee has priority for development.

However, bidding could possibly be used at the time of application for a permit as long as competition would be avoided between preference and non-preference entities. The problem with introducing bidding at this stage is that most of the good sites already have permits issued.

In an effort to determine the impact of the proposed FERC rule and of possible alternatives to it, information was collected from recent hydroelectric power project status reports provided by the Bureau of Reclamation's Mid-Pacific, Pacific Northwest, and Upper Colorado regions. These regions contain the sites of most of the hydropower opportunities where license fee rules would impact on States in the Reclamation Service area. Data from the Pacific Northwest includes only those projects located at Bureau of Reclamation facilities, while the data from the other two regions includes all potential hydropower sites.

Table 1 shows the breakdown between preference and non-preference permit holders in each region expressed as a percentage of the total number of projects in that region. Preference customers hold the majority of the permits in the Upper Colorado, but only hold about 40 percent of the permits in the other two regions.

TABLE 1

Characteristics of Permit Holders at Hydropower Sites

Region	Number of Project Sites	Preference Customers (Percent)	Non-Preference Customers (Percent)
Mid-Pacific	821	42.3	55.9
Pacific Northwest	166	42.8	56.6
Upper Colorado	179	64.2	35.8

Table 2 analyzes the extent of license competition at hydropower sites where multiple applications have been filed. Effective competition for a license at a site exists when there are applications from either: (a) two or more preference customers, (b) two or more non-preference customers, or (c) multiple preference customers and one or more non-preference customers. Current law prohibits competitive bidding for licenses between preference and non-preference customers. This means that 111 sites for which multiple applications have been filed would be affected by bidding if the rule according priority to permit holders were changed. If a bidding procedure were established, it is possible that the number of applications would increase from this level.

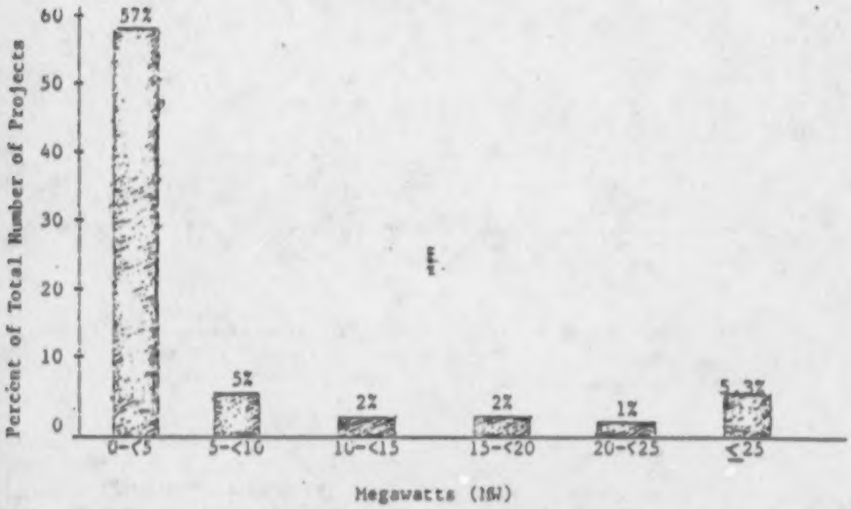
TABLE 2

Competition for Hydropower Sites

		Multiple Applicant Sites	
Region	Total Number of Sites	Single Preference Customer vs. Non-Preference Customer	Effective Competition
Mid-Pacific	821	44	58
Pacific Northwest	166	29	20
Upper Colorado	48	15	33

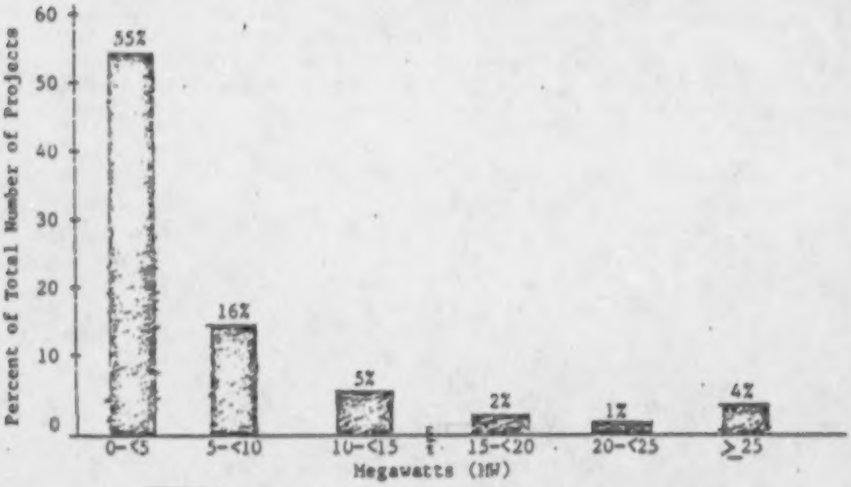
The capacities of the projects in the Mid-Pacific and Pacific Northwest regions are graphically represented to show how many projects have very small or very large potential power output. The bar graphs depict the capacities at which most projects would operate. It is clear that most of the hydrosites in the Mid-Pacific and Pacific Northwest regions are expected to have less than 5 megawatts of capacity. The remaining opportunities in both regions are similar except that there are significantly more opportunities between 5 or 10 megawatts in the Pacific Northwest region.

FIGURE 1. CAPACITIES OF PROJECTS IN THE MP REGION



NOTE: Several projects have extremely large capacities (up to 800 MW). The remaining 28 percent represents those potential projects whose capacities were not specified.

FIGURE 2. CAPACITIES OF PROJECTS IN THE PN REGION



NOTE: The largest capacity was 220 MW, with several others around 70 MW. The remaining 17 percent represents those potential projects whose capacities were not specified.

Figures 3 and 4 show that in the mid-Pacific and the Pacific Northwest regions, very similar patterns occur in the size distribution ratios between preference and non-preference customers at each capacity. The graphs reveal that in both regions, non-preference customers have more projects at the smallest capacity level (0-<5 MW) than preference customers. Preference customers dominate the higher capacity projects in both regions except at the 15-<20 MW level. However, the single highest capacity project in both regions belongs to a non-preference customer. Capcacities for the Upper Colorado region are not yet available.

FIGURE 3. PREFERENCE vs. NON-PREFERENCE CAPACITIES
MID-PACIFIC

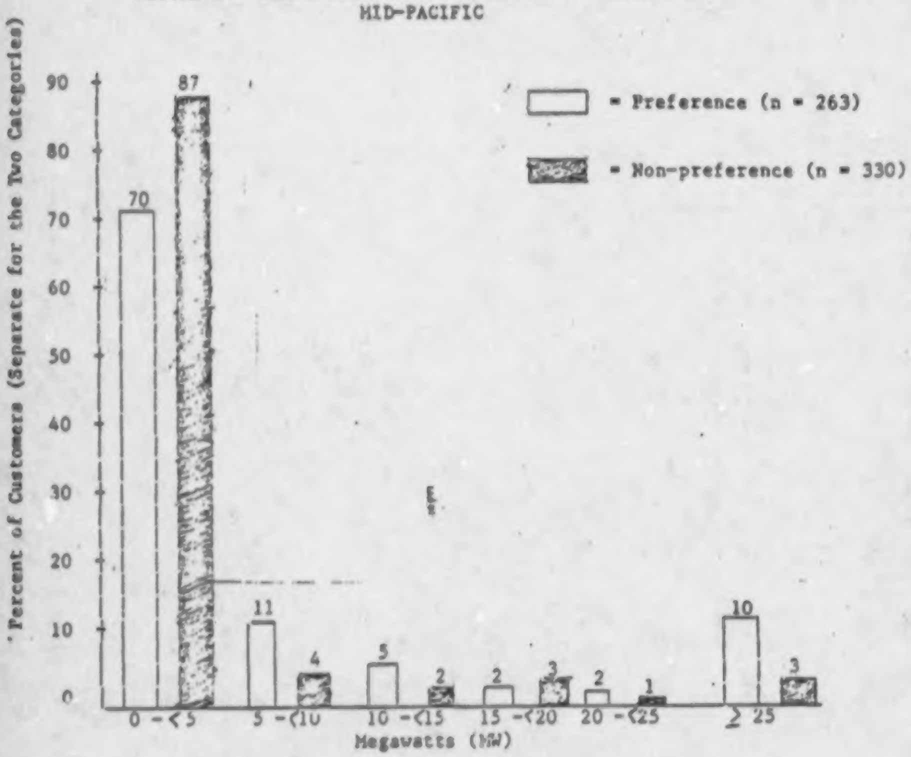
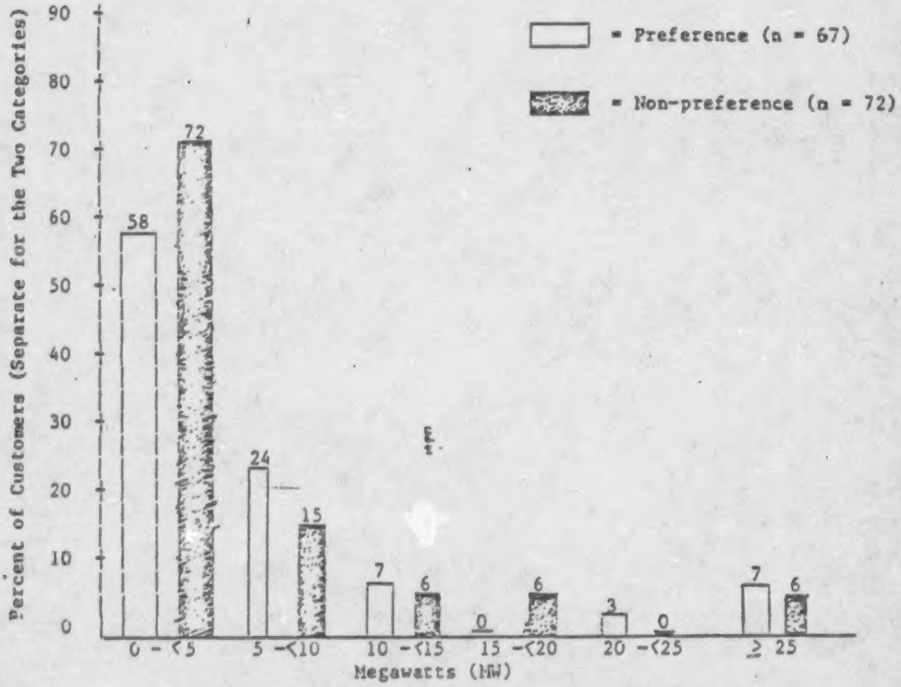


FIGURE 4. PREFERENCE vs. NON-PREFERENCE CAPACITIES
PACIFIC NORTHWEST



III. Options for Determination of Annual Charges and Site Selection

As described earlier, FERC's procedures for determining who develops the site and its procedures for determining the annual charge are independent. The selection of developer is made primarily on a first-come-first-served basis subject to a priority granted to preference customers. After granting the license, an annual charge of half of the net benefits (benefits less cost) is assessed. Under the proposed rulemaking, benefits are defined as the least cost alternative means of providing equivalent capacity for firm and non-firm energy. These benefits would be determined for each site using regional power values. Costs would be the actual construction outlays of the hydropower plant and the estimated operation, maintenance and replacement costs. The annual charge of half the net benefits would be adjusted annually by the Gross National Product deflator to maintain equal "real" values of the payments through time.

There are several options for calculating charges. Annual charges can be calculated as: (1) a flat rate based on plant capacity in kilowatts and the amount of energy generated in kilowatt hours, (2) a fixed percentage of net revenue, (3) a fixed percentage of gross revenue, or (4) a royalty or claim on some fraction of the energy produced. Alternatively, a lump sum entry fee can be employed either in place of, or in addition to, annual fees.

A standard approach used by the Federal Government to make finite fuel resources available for private development is to accept bids for the right of exclusive entry to the site and to retain the rights to a fixed percent of future production in the form of a royalty (e.g. 12-1/2 percent). Thus, the Federal Government could use the same basic approach to water power development that is used in developing its other resources. As mentioned above, the use of a bidding system at the license stage would require statute changes.

Evaluation Criteria

There are several criteria that should be considered in choosing an option for determining annual charges and choosing a non-Federal developer. Included are:

1. Economic efficiency — Does the option assure: (1) that the least cost producer receives the site and (2) that he produces all units that cost less than the value of the last unit of power produced? The consumer pays higher prices when the least cost producer does not receive the site. The economy foregoes power production when regulations prevent the developer from meeting the second part of this criterion.

2. Return to the Federal Treasury — Awarding the right to generate power at a Federal site is a public trust. This right is owned by the public at large. It should reasonably expect the highest possible return from transfer of this right to specific developers.

3. Administrative efficiency — Both the calculation of the charge and the selection of the developers should be carried out at the least cost to the Federal Government. The average number of permit applications filed with FERC for development of hydro sites increased from about four filings per year before 1978 to about 1800 filings in 1981 and has leveled off since then. With this kind of workload, it is essential that the process for setting annual charges be as simple as possible.

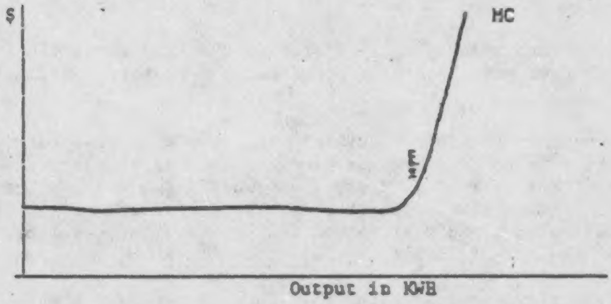
4. Removal of uncertainty -- An important component in the process of developing a site is the financial feasibility study conducted by a potential developer. Anything that delays the availability of data needed for the feasibility study or substitutes a variable factor for a firm number tends to add to the uncertainty and makes feasibility more difficult to determine. This tends to discourage the development of hydropower. Thus, the rules established for setting annual charges for the use of Federal sites should reduce uncertainty. All parties should have a clear idea of the rules of the game and these rules should be in place long enough so that anticipated returns can be realized from the private resources committed and can be reasonably estimated.

5. Acceptability to the power industry — The procedures for calculating the charge and selecting the permittee should appear reasonable to the prospective investors or there will be disincentives to participate in the development of hydropower.

Factors to be Considered in Evaluating Economic Efficiency

To evaluate an alternative based on economic efficiency, the shapes of the marginal cost curves and the demand curves facing potential hydropower developers need to be considered. The marginal cost curves for hydro projects are nearly horizontal and probably approach zero until capacity is reached. At capacity the marginal cost is nearly vertical (figure 5).

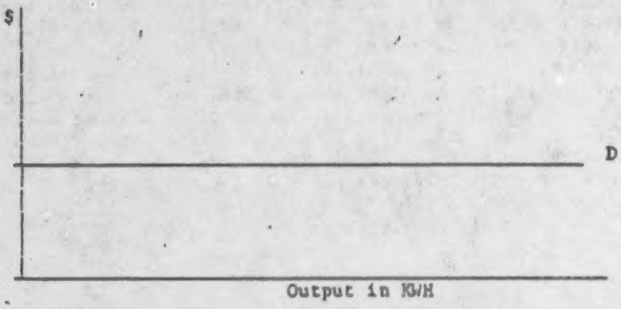
Figure 5. Marginal cost curve for a typical hydro project.



Below capacity, the additional cost of producing one more unit of energy is negligible.

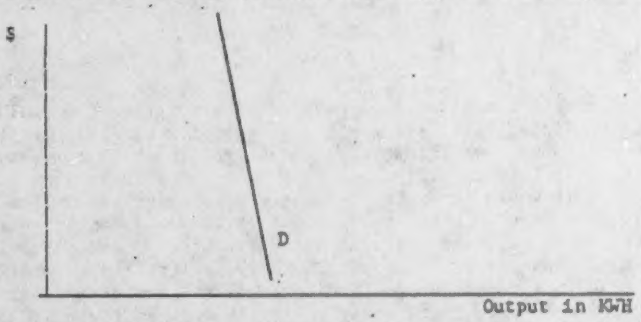
There are two different types of demand curves faced by hydropower developers. The first is the demand curve faced by a small power producer qualified under PURPA to sell power to utilities at cost avoided rates. To qualify, the power producer must have (1) a project of less than 80 megawatts, (2) use a renewable resource in power generation and (3) not have power production as its main purpose. The demand curve faced by such a small power producer is essentially horizontal, reflecting little control over the price received for the power marketed (figure 6). The small power producer gets the cost avoided rate (or more realistically a negotiated rate somewhat lower than the cost avoided rate) for all units of power that can be produced.

Figure 6. Demand curve faced by qualifying small power producer.



The second type of demand curve is one faced by a hydropower developer who is selling power to the consumers. The demand curve for electricity faced by these developers is very inelastic in the short run; i.e., quantity demanded is very unresponsive to price (figure 7). Given the existing stock of electrical appliances and equipment, consumers have a need for a certain amount of power regardless of price.

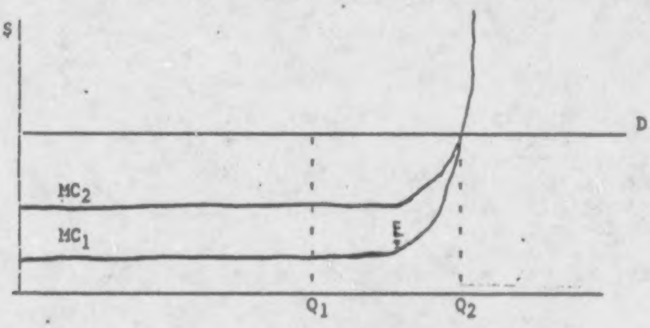
Figure 7. Demand curve faced by producer selling power to the public.



The shapes of these marginal cost and demand curves have some important implications for economic efficiency. Alternatives which would have the effect of shifting the marginal cost curve upward would have little or no effect on the quantity of energy produced.

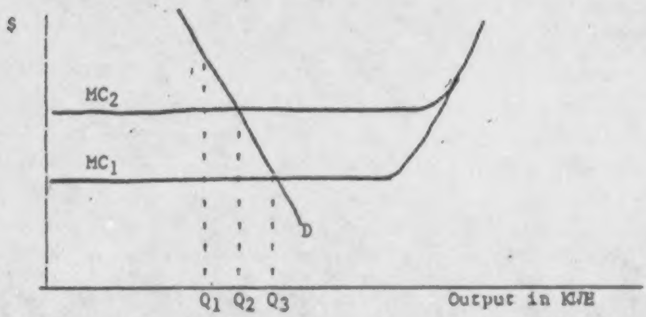
The impact on a PURPA qualifying small power producer can be explained using figure 8. Since hydro sites are typically not undersized when they are developed, the project produces all the electricity possible subject to the availability and flow of water. This means that the project is producing electricity at some level Q_1 less than capacity most of the time. Although the optimal economic solution would be to produce Q_2, rarely is the water available to produce at this level. If a regulation, such as a royalty, shifts the marginal cost curve from MC_1 to MC_2, the producer producing at Q_1 will still produce at Q_1. In fact, the producer will still produce Q_1 as long as the marginal cost curve does not shift so far upward as to lie above the demand curve.' Thus, for qualifying small power producers, regulations which have the effect of shifting the marginal cost curve upward will result in little or no loss of economic efficiency since all units that cost less than the value of power will still be produced. However, at those times when the producer is at or near capacity, there will be some loss of economic efficiency since slightly less power will be generated.

Figure 8. Qualifying small power producer



The economic efficiency impact on producers selling power to the public can be explained using figure 9. There are two possibilities here; one in which there would be no economic efficiency losses and one in which the economic efficiency losses would be small. The case in which the economic efficiency losses would be small would occur if there were sufficient water flow to produce at Q_3. If a power charge were adopted which would shift the marginal cost curve from MC_1 to MC_2, the producer would produce Q_2, and there would be a small loss in economic efficiency. The more inelastic the demand curve, the smaller is the loss in economic efficiency. Since the demand for electricity is typically very inelastic, there would be little loss in economic efficiency in this case. If there were only sufficient water flow to produce at Q_1, a shift in the marginal cost curve from MC_1 to MC_2 would result in no loss in economic efficiency. The producer would still produce at Q_2.

Figure 9. Producer selling power to the public



In setting annual charges for the use of Government dams, other objectives stated in the Federal Power Act must also be considered. Charges must be set so that (1) the Government receives an adequate return for the use of its resources, (2) the price of power to consumers is kept as low as possible, and (3) the development of hydropower is encouraged. Clearly, some of these objectives are conflicting and tradeoffs must be made in establishing a process for determining actual annual charges. The higher the annual charge, the greater is the return to the Government. However, some forms of higher annual charges can be passed through to consumers in the form of higher prices through the rate making process. Also, some forms of higher annual charges tend to discourage the development of hydropower. As most recently expressed in PURPA, Congress seems to place the highest priority on the develoment of hydropower and keeping cost to consumers low.

IV. Alternatives for Setting Annual Charges for the Use of Government Dams

The first five alternatives assume that the developer is chosen according to current FERC procedures, generally the permittee receives the site.

Alternative 1. Fifty percent of regionalized net benefits

This alternative is currently being proposed by FERC. It is a four step approach which involves:

a. determining on a regional basis the annual cost of power from the least expensive alternative power source (power value) and using this as the measure of benefits;

b. determining the annual cost of hydroelectric project power (project powerhouse costs) using actual project construction costs;

c. determining net benefits by subtracting powerhouse costs from power benefits; and

d. charging the licensee 50 percent of the levelized net benefits for the privilege of developing hydroelectric power at a Government dam or other structure. Levelized means determining a series of uniform annual amounts, which, over a specified period, would result in the same aggregate present value as a series of varying estimated annual amounts.

FERC proposes an extensive data collection and modeling effort to determine power values for between 18 and 20 regions nationwide. These data are to be updated annually.

Discussion: This proposed rule is complex. Significant staff time would be required to compile the necessary data and to calculate the regional power values. Additional time would be necessary to make all the necessary calculations for each project. Therefore, it is unclear how much savings there would be in administrative costs when compared with current FERC procedures. This proposed rule would take more expertise on the part of developers than is currently the case. It would almost ensure that a consultant would need to be retained to perform the annual charge calculations.

The use of actual project costs in determining the net benefit would mean that the actual annual charge would not be known to the developer until after the project was completed. Currently, the actual annual charge is determined during the licensing procedure and is known by the developer before project construction begins. Therefore, the proposed procedures would increase both uncertainty over the charges to be levied and would likely increase administrative costs both for the developer and for FERC. The additional cost and administrative burden would tend to discourage the development of hydropower at some sites.

The use of actual costs in determining net benefit would have a weaker incentive for developers to reduce actual project costs compared with current FERC procedures. The developer would realize 50 percent of the cost savings under this alternative, but would realize 100 percent of cost savings under the current FERC procedures.

Calculating estimated benefits using regional power values could be a real problem. A basic and fallacious assumption underlying this approach is that revenue potentials are similar for all energy producers within a region. Thus, this approach will work well only if the rate structures faced by projects within a region are fairly homogeneous. This forces a tradeoff administrative burden to FERC and the accuracy of estimated revenues to the developer. The larger the regions, the greater is the likelihood that they will lack homogeneity. The smaller the regions, the greater will be the administrative burden in calculating regional power values while revenue potentials will be more accurately measured.

The process of levelizing costs and benefits may be fine for analyzing project feasibility; however, it seems to be a poor basis on which to charge an annual fee. The process of levelizing spreads costs, which tend to be high initially and low thereafter, into the future. It also spreads revenues, which tend to be small initially and increase with time, back to the present. Charging one-half of the levelized net benefits could give a developer a severe cash flow problem, since actual costs and revenues would probably be quite different than levelized costs and revenues. The option to defer payment of annual charges during the first 10 years could mitigate this problem. However, the problem could be completely avoided if an alternate method of determining annual charges that more closely reflects actual annual costs and revenues were used.

The sharing of net benefits method proposed by FERC may not reflect the real world of hydroelectric power marketing. Under PURPA, qualifying small-scale power producers are entitled to sell hydroelectric power to public utilities at a rate equal to the cost the utility avoids by not generating or purchasing that increment of power. State public utility commissions have promulgated orders defining these "avoided costs" on a utility-specific basis. Avoided cost rates serve as a basis for negotiation between a small-scale hydroelectric developer and a public utility. In large measure, the hydroelectric developers' revenues are defined by the avoided cost rates. The method of determining annual charges proposed by FERC would base such charges on the theoretical value of the power, irrespective of the actual revenues obtained by a small-scale hydroelectric developer from the sale of that power. Therefore, FERC could simplify the calculation of annual charges by using the applicable avoided cost rate as a measure of benefits for plants which are qualified under PURPA. This would greatly reduce administrative cost of determining power benefits and would substitute an accepted market test for the value of power in place of a less certain regional calculation.

Analysis:

a. Economic efficiency: This alternative does not ensure that the least cost producer receives the site because the decision is based on first-come-first-served. The developer receiving the site does have the incentive to produce all units that cost less than the value of the power produced since the marginal costs faced by the producer are not altered by a fixed annual charge.

b. Return to the Federal Treasury: Higher than the current method. Being linked to the GNP deflator, returns to the Treasury will probably increase over time.

c. Administrative efficiency: This alternative is more complex than the current method and would result in increased administrative burden.

d. Removal of uncertainty: This alternative increases the uncertainty to developers over the present method used to assess annual charges because it is not determined until project completion.

e. Acceptability to power industry: Initial indications are that this alternative is viewed as very unfavorable by the power industy. The charges are difficult to compute under this alternative. This alternative is seen as discouraging the development of hydropower.

Alternative 2. Flat Rate Charge

This alternative would charge a fixed dollar amount per kilowatt of installed capacity and a fixed mil amount per kilowatt hour of power produced. This flat rate charge could be linked to some electricity rate index to ensure a fair return to the Government.

Analysis:

a. Economic efficiency: This alternative would not ensure that the least cost producer received the site. There would be little or no loss in output since all or almost all of the units that cost less than the value of the power would be produced, as explained above. Depending on the amount of the charge some of the more marginal projects would not be constructed.

b. Return to the Federal Treasury: Depending on the levels set revenues could approach but would probably not be as great as alternative 1. If a flat rate charge were used without indexing, the Government would not share in any increase in power rates and the developer could be excessively burdened by any decrease in power rates.

c. Administrative efficiency: This alternative is truly a generic approach and would be very easy to administer.

d. Removal of uncertainty: This alternative would remove all uncertainty about annual charges if it were not linked to an index and would still remove much of the uncertainty if annual charges were linked to an index.

e. Acceptability to power industry: Initial indications are that this alternative is very acceptable to the power industry. It is easy to calculate and use in any feasibility analysis. This alternative is viewed as encouraging the development of hydropower.

Alternative 3. Percentage of Net Revenues

This alternative would base the annual charge on a fixed percentage of the actual net revenues accruing to the developer of a site.

Analysis:

a. Economic efficiency: This alternative does not ensure that the least cost developer receives the site. There would be little or no loss in economic efficiency since the developer receiving the site has the incentive to produce all or almost all of the units that cost less than the value of the power produced.

b. Returns to the Treasury: Returns could be approximately equal to the returns under alternative 1 over the life of the project. For example, if the percentage were fixed at 50 percent of net revenues, this should be approximately equal to 50 percent of net benefits. The Government would share in any increases or decreases in the value of electricity. Annual charges would be based on actual rather than estimated data.

c. Administrative efficiency: The use of net revenue would entail a large annual administrative burden for FERC in the form of compliance checks probably resulting in larger administrative costs than any other option. This would also weaken the incentive to control costs.

d. Removal of uncertainty: Since annual charges are some known percentage of net revenues, this alternative would remove the uncertainty from the process of setting annual charges.

e. Acceptability to the power industry: This alternative would not be very acceptable to the power industry. The use of actual net revenues would require the developer of a site to maintain detailed cost accounts. One of the purposes of PURPA was to relieve them of this burden. Also, the valuation problem for power produced for internal use would exist.

Alternative 4. Percentage of Gross Revenue

This alternative would base the annual charge on a fixed percentage of actual gross revenues accruing to the developer of a site.

Analysis:

a. Economic efficiency: This alternative would not ensure that the least cost producer received the site. There would be little or no loss in output since all or almost all of the units that cost less than the value of the power would be produced, as explained above.

b. Returns to the Treasury: Returns would be greater than under alternative 2, but not as large as under alternatives 1 and 4. The Federal Government would share in any increases or decreases in the value of electricity.

c. Administrative efficiency: An annual charge based on percentage of gross revenue would be very easy to administer, although it would require more accounting data than alternative 2.

d. Removal of uncertainty: Since annual charges are some known percentage of gross revenues, this alternative would remove most of the uncertainty from the process of setting annual charges.

e. Acceptability to the power industy: Some marginal projects would be eliminated. The table below shows the benefit-cost ratio needed for a developer to break even on a project at different percentages of gross revenues.

Charges as a Percentage of Gross Revenues	Benefit-Cost Ratio Needed to Break even
0	1.00
5	1.05
10	1.11
15	1.18
20	1.25
25	1.33

With an annual charge of 5 percent of gross revenues, any project with a benefit-cost ratio of less than 1.05 would not be profitable and hence would not be undertaken. This table illustrates the tradeoff between increasing returns to the Government and the elimination of marginal projects. This alternative is viewed as the second most acceptable option by the power industry with alternative 2 being the preferred option. A valuation problem for power produced for internal use would exist.

Alternative 5. Percentage of Power Produced (Royalty)

This alternative would make the annual charge some fixed percentage of the power produced by the project, similar to the method used in oil and gas leases. The power could be used by the Government for its own purposes, marketed by the Federal power marketing agencies or marketed by the developer for the Federal Government.

Analysis:

This is similar to alternative 4 above and the same analysis would apply. This alternative is more general than option 4 because it would cover not only projects where revenue is produced but also projects in which the developer uses the power for other project purposes, such as irrigation districts, and no revenue is produced from the sale of electricity unless there is surplus power.

Alternative 6. Bonus bid or Entry Fee

This alternative would call for a bonus bid or entry fee which could be implemented separately or in addition to alternatives 2 through 5 above. Within certain restrictions explained below, the highest bidder receives the license to develop the site with payment required as a lump sum prior to construction commencing. The steps in the bidding process are as follows:

1. The first entity to apply for a permit to study a particular site would be awarded the permit. All information collected during this study would be publicly available.

2. All parties interested in submitting a bid for the license for a site would need to be qualified. FERC would qualify potential bidders under currently used criteria, e.g., financial ability, safety of the

project works and operation, environmental factors, suitability of the proposed project to the site, and any other factors deemed to be in the public interest.

3. Sealed bids would be submitted with the highest bid receiving the site subject to:

   a. A bid by a qualified preference entity eliminates all non-preference entities from the bidding.

   b. The permit holder has two choices if it is not the highest bidder:

      (1) Match the highest bid and be awarded the license. This does not apply if the permit holder is a non-preference entity and the highest bidder is a preference entity.

      (2) Be compensated for the cost of doing the feasibility study.

Discussion: The bonus bid serves the purpose of selecting who gets the opportunity to develop the site and would change the current practice of awarding the site on a first-come-first-served basis. The Government is compensated for the power privilege pertaining to a site both through the bonus and through the charges applicable under one of the alternatives 2 through 5 above.

Sites with higher benefit-cost ratios have higher profits. These higher profits, sometimes referred to as economic rent, may be viewed as unearned by the developer since they result from the characteristics of the site rather than from the resources or management ability of the developer. It could be argued that the Federal Government would not receive an adequate return on its resources from sites with high benefit-cost ratios if annual charges were set using alternatives 2 through 5. The FERC proposal, alternative 1, is an attempt to extract some of the economic rent pertaining to a particular site, but is not as satisfactory as bonus bidding which relies on market-based cost and revenue estimates. When there is potential competition a developer would have the incentive to bid a high proportion of his economic rent. Therefore, this alternative would result in the highest Federal revenue. Moreover, the lowest cost producer could bid more for the site than higher cost producers which would enhance economic efficiency by assuring the low cost producer gets the site.

Analysis:

a. Economic efficiency: This alternative would assure that the least cost producer receives the site. There would be no loss of economic efficiency since all of the units that cost less than the value of the power would be produced. This alternative ranks higher in economic efficiency than any other option considered.

b. Returns to the Treasury: Returns to the Treasury would depend on the number of bidders. With the threat of competition from even two or three bidders, a good deal of the economic rent pertaining to a site could be received.

c. Administrative efficiency: Administrative costs would be incurred in establishing the bidding process, in holding the sale, and in evaluating the bids, but would be negligible thereafter. The administrative costs of this alternative would probably be higher than alternatives 2, 4, or 5, but lower than 1 or 3. The increased administrative costs would be more than offset by the increased revenues received from the bonus bids.

d. Removal of uncertainty: A developer could not be certain of bidding the highest and receiving the site. However, each developer would know exactly what the cost would be if he were to receive the site, namely the amount bid.

e. Acceptability to the power industry: There does not seem to be any great enthusiasm for bidding on the part of the power industry and this would be a new concept for awarding sites to potential developers.

V. Recommendations

Absent legal and institutional constraints, it would be recommended that alternative 6 be adopted (competitive bidding) in conjunction with alternative 5 (annual fee as some fixed percentage of the power generated). Alternative 6, used in conjunction with alternative 5, would provide both a means of assuring the least cost producer is selected to develop a site and of extracting, in the limit, economic rent pertaining to a site not collected by the annual charge. The adoption of this combination of alternatives would result in a process which is economically efficient, ensures a reasonable return to the Government, and is easy to administer.

However, there are legal and institutional constraints to consider. Alternative 5 is in accordance with existing statutes. Unfortunately, alternative 6 is not. Section 5 of the Federal Power Act gives a preliminary permit holder a "priority of application for a license" for a period not to exceed 3 years. The preference granted under section 7(a) to municipalities, irrigation districts, etc., does not prevail over a permit holder's timely application for license, provided the plans are equally well adapted. Thus, the bonus bid would be contrary to the letter and intent of the Federal Power Act if it resulted in awarding the license to either a preference or a non-preference applicant because of a high bid when the permit holder's application is equally well suited. The use of any bidding program for the purpose of determining who receives the right to develop the site would take a revision of the Federal Power Act even when the program recognizes the priority of the preference customers. Thus, it is not possible under existing statutes to ensure that the least cost developer receives the site. This means as previously mentioned that the consumer is not receiving the lowest possible prices for power and that the Treasury is not guaranteed maximum returns.

There are two courses of action that could be adopted; one feasible under existing statutes and the other requires a change. The first is to set annual charges based on a fixed percentage of power produced instead of either the current or proposed FERC procedures. This option is easy to administer, removes the uncertainty on the part of developers, and requires no changes in current statutes. No attempt would be made to extract economic rent pertaining to a site in excess of this annual charge. Experience with some Government leasing programs indicates that the bulk of the returns to the Treasury are generated by the royalty rather than by the bonus. Thus, adoption of this alternative assures a reasonable return to the Treasury for the use of the site. An analysis of data from actual projects found that in most cases an annual charge based on 5 percent of the gross revenues was approximately equal to the actual annual charge computed according to current FERC procedures.

The second course of action is to press for limited revision of the Federal Power Act to allow for the possibility of using bonus bids to detemine who receives the site in combination with a royalty. This would make it possible to ensure that the lowest cost producer received the site and to extract any economic rent pertaining to a site. It would increase returns to the Treasury and make the leasing of Federal dams compatible with the procedures used in leasing other federally-owned resources. This second course of action is the one which we prefer.

Enclosure 5

Suggested Department of the Interior Amendments to S. 1132

1. To adopt the royalty approach. On page 2, line 4, strike out "in addition to an annual rental charge not to exceed $1 per kilowatt of installed capacity and one-half mil per kilowatt-hour of energy produced," and insert in lieu thereof "in addition to an annual rental charge not to exceed 5 per centum of the [redacted] electricity produced,".

2. (a) To allow bidding for the license to develop the site. After page 2, line 8, add the following new section:

SEC. 2 Section 5 of the Federal Power Act (16 U.S.C. 798) is amended by striking out "for the sole purpose of maintaining priority of application for a license under the terms of this Act" and "Each such permit shall set forth the conditions under which priority shall be maintained." and by inserting after the last sentence "All information collected under this permit shall be available to the public.".

(b) To mandate bidding for the license. In addition to a new section 2, add the following new section:

SEC 3. Section 6 of the Federal Power Act (16 U.S.C. 799) is amended by redesignating section 6 as section 6(c) and by inserting immediately before (b) the following new subsections:

> "(a) Sealed bids shall be submitted to the Commission with the highest bid receiving the license to develop the site. The Commission shall ensure that the highest bidder is qualified to develop the site with respect to financial ability, safety of the project works and operation, environmental factors, suitability of the proposed project to the site, and any other factors deemed to be in the public interest. If the highest bidder is not qualified, the next highest qualified bidder shall receive the license to develop the site.
>
> "(b) A bid by a qualified preference entity shall eliminate all nonpreference entities from the bidding. If the permit holder is not the highest bidder, such holder shall either: (1) match the highest bid and be awarded the license, unless the permit holder is a nonpreference entity; or (2) be compensated by the entity receiving the license for the cost of conducting the feasibility study."

To allow annual charges for Bureau of Reclamation sites to be paid into the Reclamation Fund.

On page 2, after line 8, add the following new paragraph:

> "Section 17(a) of the Federal Power Act (16 U.S.C. 810) is amended by modifying the last clause of the second sentence to read as follows: "50 per centum of the charges arising from all other licenses, other than those for the use of Bureau of Reclamation facilities, hereunder is reserved and appropriated as a special fund in the Treasury to be expended under the direction of the Secretary of the Army in the maintenance and operation of dams and other navigation structures owned by the United States or in the construction, maintenance, or operation of headwater or other improvements of navigable waters of the United States; and 50 per centum of all charges whatsoever arising from all licenses hereunder authorizing in any manner the use of Bureau of Reclamation structures and facilities shall be paid into the Reclamation Fund."

This amendment would clarify the Federal Power Act to ensure that part of the money collected by the Federal Energy Regulatory Commission for the so-called "falling water charge" and the use of Reclamation facilities would be deposited in the Reclamation Fund.

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

AUG 22 1983

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 24 1983
WASHINGTON, D.C. 20510

Honorable James A. McClure
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

This is in response to your request of June 13, 1983, for the views of the Office of Management and Budget on S. 1132, a bill "To amend the Federal Power Act to specify the annual charges for projects with licenses issued by the Federal Energy Regulatory Commission for the use of Federal dams and other structures."

The Office of Management and Budget concurs in the views of the Department of the Interior as expressed by Assistant Secretary Garrey E. Carruthers and of the Department of the Army as expressed by Major General John F. Wall, in their testimony of July 23, 1983, before the Water and Power Subcommittee. Accordingly, we oppose enactment of S. 1132.

Sincerely,

James M. Frey

James M. Frey
Assistant Director for
Legislative Reference

DEPARTMENT OF THE ARMY
OFFICE OF THE CHIEF OF ENGINEERS
WASHINGTON, D.C. 20314

REPLY TO
ATTENTION OF:
Office of Policy

Official Committee File
2 3 AUG 1983

SENATE COMMITTEE ON
[illegible]
AUG 2 4 1983

Honorable James A. McClure
Chairman
Committee on Energy and Natural
  Resources
United States Senate
Washington, D. C. 20510

Dear Mr. Chairman:

This is in response to your letter of August 4, 1983, concerning a followup question to my testimony at the July 25, 1983, committee hearing on S. 1132.

The requested information is enclosed.

Sincerely,

C E Edgar III
for
John F. Wall
Major General, U. S. Army
Director of Civil Works

Enclosure

C.E. EDGAR III
Brigadier General, U.S. Army
Deputy Director of Civil Works

QUESTION: John Baird, in his written testimony on behalf of the Columbia Basin Irrigation Districts, suggested an amendment that would exempt from charge any licensee that has a contract with the United States that provides that no charge shall be imposed.

(a) Please comment on this proposed amendment.

(b) Please provide the Committee with a list of all non-Federal entities that would be exempted by this amendment.

ANSWER: (a) As mentioned in my testimony on S.1132, we would object to enactment of the bill since it could inhibit agreements (or "contracts") between a Federal agency and a potential non-Federal sponsor or financial responsibilities associated with the construction of hydroelectric facilities at a Federal dam. As a separate matter, however, we would not object to the idea that no other license charge be assessed to a FERC licensee if that licensee has a legally binding agreement with the Corps of Engineers regarding sharing the cost of hydroelectric power development, so long as that agreement is in effect. However, since license charges are administered by the FERC, that agency should address this matter.

(b) As of now, we have not finalized any hydropower cost sharing agreements with FERC licensees.

APPENDIX II

Additional Material Submitted for the Record

JAMES A. MC CLURE, IDAHO, CHAIRMAN
MARK O. HATFIELD, OREG.
LOWELL P. WEICKER, JR., CONN.
PETE V. DOMENICI, N. MEX.
MALCOLM WALLOP, WYO.
JOHN W. WARNER, VA.
FRANK H. MURKOWSKI, ALASKA
DON NICKLES, OKLA.
CHIC HECHT, NEV.
JOHN H. CHAFEE, R.I.
JOHN HEINZ, PA.
J. BENNETT JOHNSTON, LA.
HENRY M. JACKSON, WASH.
DALE BUMPERS, ARK.
WENDELL H. FORD, KY.
HOWARD M. METZENBAUM, OHIO
SPARK M. MATSUNAGA, HAWAII
JOHN MELCHER, MONT.
PAUL E. TSONGAS, MASS.
BILL BRADLEY, N.J.
MICHAEL D. HATHAWAY, STAFF DIRECTOR
CHARLES A. TRABANDT, CHIEF COUNSEL
D. MICHAEL HARVEY, CHIEF COUNSEL FOR THE MINORITY

1983 Official Committee File

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C. 20510

July 29, 1983

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
AUG 1 1983
WASHINGTON, D.C. 20510

The Honorable James A. McClure
Chairman
Committee on Energy and Natural
Resources
United States Senate
SD-361
Washington, D. C. 20515

Dear Chairman McClure:

On July 25 the Full Committee held hearings on the new proposed rule governing annual charges for use of Governmental dams and the "sharing of benefits" issue.

Willwood Irrigation District asked that I share the enclosed material with you and asked that this correspondence be included in the record.

Thank you for your time and cooperation.

Sincerely,

Malcolm Wallop

Malcolm Wallop
United States Senator

MW:tsp

Enclosure

WILLWOOD IRRIGATION DISTRICT
POWELL, WYOMING
82435

1983 JUN 13 AM 10:40

June 3, 1983

Senator Malcolm Wallop
6327 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator Wallop:

Enclosed is a copy of our comments to F.E.R.C. on their proposed rules for use of Federal Dams and Structures for private hydro-electric development.

Upon further study of the rules, we see more serious problems.

F.E.R.C. apparently proposes to rewrite existing Bureau of Reclamation contracts with irrigation districts such as ours by declaring juristiction over the development of electrical projects on dams or other structures that were built by the Bureau and assigned to the irrigation districts under repayment contracts (see Vol. 48, No. 68, Sub H. Especially note the word "independent" in footnote #72, Federal Register, Thursday, April 7, 1983 enclosed.)

When the first Board of Commissioners of the Willwood Irrigation District signed the repayment contract (copy enclosed) we are sure that they thought the USBR was acting in good faith. That contract did not have any reservation of the electric power provision of the Willwood Dam to the Federal Government. We can only assume that the power provision was intended to be transferred. The fact that the penstock was already in place and its cost must have been included in the amount to be repaid, surely substantiates this conclusion.

We are currently negotiating with the Wyoming Water Development Commission for a loan to install a generator at Willwood Dam. The Commission members have expressed concern over our ability to repay if the "Falling Water Charge" is enforced or if this new "charge" is enforced by F.E.R.C.

We too, feel that the economics become impossible if the profits must be split with the Federal Government.

Our small District does not have funds enough to take the various agencies to Federal Court to attempt to force compliance with our contract so we are appealing to you in hopes of securing some aid in persuading the Bureau and FERC to recognize our contract as it was written thus setting aside the latter (1956) added commissioner interpretation of a prior law (1939). To have F.E.R.C. attempt to make similar power moves through its rule making process only adds salt to the already bleeding wound.

Surely there must be something that can be done to firm up our existing contract without these added complications. Any help you or your staff can give us will be appreciated by all the people of this District.

Sincerely,

Merlin E. Borcher
Merlin Borcher,
Chairman, Board of Commissioners

Laness Northrup
Laness Northrup,
Commissioner, Project Liaison Officer

LN/jlb
Encl:
cc:

cc: Wyoming Water Development Comm.
Barrett Building, 4th Floor
Cheyenne, Wyoming 82002

cc: Joseph B. Marcotte, Jr.
Regional Director
Bureau of Reclamation
P.O. Box 2553
Billings, Montana 59103

cc: Dick Mascolo
Stone & Webster Engineering
P.O. Box 5406
Denver, Colorado 80217

cc: Senator Alan Simpson
6327 Dirksen Senate Office Building
Washington, D.C. 20510

cc: Rep. Dick Cheney
House of Representatives
Washington, D.C. 20515

WILLWOOD IRRIGATION DISTRICT
POWELL, WYOMING
82435

May 11, 1983

Secretary
Federal Energy Regulatory Commission
825 N. Central Street N.E.
Washington, D.C. 20426

Subject: Docket # RM 83-13-000

Dear Sir:

We are taking this opportunity to offer our comments on Docket # RM 83-13-000, the proposed rule governing annual charges for use of Governmental dams and particularly to the topic "Sharing of the Benefits" on which the Commission invited specific comment.

Willwood Irrigation District's particular area of concern is the appropriateness of the current 50%-50% sharing of the net benefits for small power projects using a federal dam or other structure. This District is presently in the licensing process of a two (2) MW hydro installation at Willwood Dam, Powell, Wyoming, a Bureau of Reclamation constructed dam, the cost of which is currently being repaid in full under a repayment contract with the Bureau of Reclamation. The outcome of this proposed rule making will have a profound affect on our plans and undoubtedly on many others undertaking similar small hydro developments.

It is generally recognized that in contrast with large scale hydro, small hydro suffers some serious economic disadvantages. That is to say, small hydro is generally more costly per KW of installed capacity and per KWH of output than large scale hydro. This is due mainly to the higher cost per KW of the small capacity equipment and also because most small projects are medium to low head. This low head feature means relatively large water requirements which leads to larger size and costly civil and mechanical features in contrast with higher head projects. Even when the small project has a high head it usually involves a long flow line again leading to relatively high unit costs.

Considering the higher costs per KW inherent in small projects and the risk of return that can be jeopardized by small changes in project conditions, reducing the potential net benefits to the developer by 50% without reducing the risk, can make an otherwise viable project economically unattractive. A 50% net benefit no doubt will reduce the rate of return on a number of projects to the point that they will not be developed.

We recognize that the Commission is probably required to fix some charge for a non-federal entity developing power at a governmental dam. We believe that the 50%-50% split of the net benefits should not be applied to all projects. We believe that the charge for small power projects should be nominal in order to help offset the above economic impediments, and thus support the national energy policy favoring development of this renewable source of power.

Merlin E. Borcher
Merlin Borcher,
Chairman, Board of Commissioners

Laness Northrup
Laness Northrup,
Commissioner, Project
Liaison Officer

Encl:
LN/jlb
cc:

cc: Laness Northrup

cc: See attached

Richard Mascolo
Stone & Webster Engineering
P.O. Box 5406
Denver, Colorado 80217

cc: Dave Zelenka
Wyoming Water Development Commission
Barrett Building, 4th Floor
Cheyenne, Wyoming 82002

cc: Larry J. Wolfe
Assistant Attorney General
State Capitol Building
Cheyenne, Wyoming 82002

cc: Joseph B. Marcotte, Jr.
Bureau of Reclamation
P.O. Box 2553
Billings, Montana 59103

cc: Representative Dick Cheney
House of Representatives
Washington, D.C. 20515

cc: Senator Malcolm Wallop
6327 Dirksen Senate Office Building
Washington, D.C. 20510

cc: Senator Alan Simpson
6327 Dirksen Senate Office Building
Washington, D.C. 20510

cc: Nelson E. Wren, Jr. (Chairman)
P.O. Box 45
Savery, Wyoming 82332

cc: Walter J. Pilch (Vice Chairman)
P.O. Box 6498
Sheridan, Wyoming 82801

cc: Lewis Freudenthal (Secretary)
Owl Creek Rt.
Thermopolis, Wyoming 82443

cc: Lee Coffman
P.O. Box 64
Powder River, Wyoming 82648

cc: Kenneth Kennedy
P.O. Box 1089
Wheatland, Wyoming 82201

cc: William J. Kirven, Jr.
104 Fort
Buffalo, Wyoming 82834

cc: James Noble
Box 14
Cora, Wyoming 82925

cc: Willard C. Rhoads
P.O. Box
Cody, Wyoming 82414

WILLWOOD IRRIGATION DISTRICT
POWELL, WYOMING
82435

June 2, 1983

Wyoming Water Development Commission
Barrett Building, 4th Floor
Cheyenne, Wyoming 82002

TO: ALL MEMPERS

Enclosed are some copies of our comments to F.E.R.C. on its proposed rules for power development at Federal Dams together with a copy of our repayment contract, and a letter sent to members of the Wyoming Congressional Delegation asking for their help to somehow firm up the status of our contract.

It is on the basis of this contract that we have been negotiating with W.W.D.C. for a loan for the power plant at Willwood Dam. We maintain that this is a firm contract giving us the right to develop the power provision that was in place when the contract was executed.

We are sure you agree, we must have something recognizing the validity of our contract with the U.S. in order to proceed with the construction phase or Level III.

We are wondering if possibily the Commission might request aid from other divisions of the State Government to bring some sort of added pressure on the Bureau of Reclamation and F.E.R.C. to recognize this contract and not try to ex post facto amend it.

Any help that you individually or collectively can give us will be appreciated.

Sincerely,

Laness Northrup

Merlin Borcher,
Chairman, Board of Commissioners

Laness Northrup,
Commissioner, Project Liaison Officer

LN/jlb
Encl:
cc:

cc: Laness Northrup

cc: Dick Mascolo
Stone & Webster Engineering
P.O. Box 5406
Denver, Colorado 80217

cc: Joseph B. Marcotte, Jr.
Regional Director
Bureau of Reclamation
P.O. Box 2553
Billings, Montana 59103

cc: Larry J. Wolfe
Assistant Attorney General
State Capital Building
Cheyenne, Wyoming 82002

cc: Senator Malcolm Wallop
6327 Senate Office Building
Washington, D.C. 20510

cc: Senator Alan Simpson
6327 Dirksen Senate Office Building
Washington, D.C. 20510

cc: Representative Dick Cheney
House of Representatives
Washington, D.C. 20515

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION

SHOSHONE PROJECT, WYOMING

CONTRACT BETWEEN THE UNITED STATES AND WILLWOOD IRRIGATION DISTRICT

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UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION

SHOSHONE PROJECT, WYOMING

CONTRACT BETWEEN THE UNITED STATES AND WILLWOOD IRRIGATION DISTRICT

1. THIS CONTRACT, made this 13th day of May, 1949, between the UNITED STATES OF AMERICA (hereinafter called the United States), acting through the Secretary of the Interior (hereinafter called the Secretary), and pursuant to the Federal Reclamation Laws, and the WILLWOOD IRRIGATION DISTRICT, an irrigation district organized and existing under and by virtue of the laws of the State of Wyoming (hereinafter called the District), with its principal place of business and office at Powell, Wyoming,

WITNESSETH THAT:

2. WHEREAS, the United States has provided necessary irrigation works for the Willwood Division of the Shoshone Project; and proposes, if funds are appropriated therefor by Congress and insofar as the cost thereof is covered by the District obligation described below in Article 9 (a), to provide additional and supplementary irrigation and drainage works for said Willwood Division; which Division consists of approximately eleven thousand five hundred ninety-five (11,595) acres of available land in Park and Big Horn counties, Wyoming, which land is specifically described in Exhibit A which is by this reference made a part hereof;

3. WHEREAS, Shoshone Project Public Orders Nos. 38, 40, 41, 43, 46, and 48 announced the opening of public lands to entry on the Willwood Division and provided, among other things:

a. That different classes of land under the Division should bear different construction charges in accordance with their productive value;

b. That when sufficient settlers had entered the lands of the Division, an irrigation district would be organized and a "so-called joint-liability contract" covering the payment of construction charges would be required;

c. That until such "joint-liability contract" had been executed or until a public notice had been issued, water would be made available to the individual entryman or land-owner upon his or her execution of a water-rental application; and

4. WHEREAS, the district has been organized pursuant to the provision noted above in Article 3 (b) and now desires to execute the so-called joint-liability contract in accordance with the stated requirement of the cited public orders;

NOW THEREFORE, in consideration of the mutual and dependent covenants herein contained, it is agreed as follows:

DEFINITIONS

5. Where used in this contract, the terms:

a. "Secretary" or "contracting officer," or either of them, shall mean the Secretary of the United States Department of the Interior, or his duly authorized representative;

b. "Federal Reclamation Laws" shall mean the Act of June 17, 1902 (32 Stat. 388), and all acts amendatory thereof and supplementary thereto, including particularly, without limitation of the foregoing, the Reclamation Project Act of 1939;

c. "Year" shall mean the period January 1, through the next following December 31;

d. "Irrigation Season" shall mean the period April 25 through October 25 within any year;

e. "District water supply" shall mean the estimated amount of water available for the irrigation of lands under the District, for any irrigation season, as determined by the Secretary. Such amount shall, insofar as practicable, be that quantity which may be applied beneficially in accordance with good usage in the irrigation of lands under the District. In case of a shortage at any time, such amount shall be an equitable proportionate share of the water for irrigation actually available for all of the area being watered from the same source of supply.

f. "District irrigation works" shall mean the following property located on the Willwood Division: the Willwood diversion dam and appurtenant works; all canals, laterals, open and closed drains and appurtenant structures; telephone system; the U. S. Reserves, with buildings and appurtenant structures thereon, described as Tract Twenty-two (22), Section Nine (9), Township Fifty-four (54) North, Range Ninety-eight (98) West; Lot Forty-three (43) B-b, Township Fifty-four (54) North, Range Ninety-nine West; Lots Fifty-nine (59) W-a, Thirty-nine (39) V-b, Forty-four (44) A-a, Township Fifty-five (55) North, Range Ninety-nine (99) West.

g. "Reserved works" shall mean the Buffalo Bill Dam and Reservoir and structures and buildings appurtenant thereto, and all other works and property, real and personal, of the United States used in connection with the Willwood Division except the District irrigation works above-described in Subarticle f.

UNITED STATES TO TERMINATE TEMPORARY APPLICATIONS

6. The United States shall terminate all Applications for Temporary Water Service and Permanent Water-right covering the lands within the District and shall release the liens reserved in such applications upon judicial confirmation of the District electors' authorization of this contract as herein provided in Article 28: Provided, That no lien reserved in such application shall be released until the owner of the land covered by the lien shall consent in writing to the District's assessment, levy and collection of taxes against said land for payment to the United States of the contract obligation.

UNITED STATES TO FURNISH WATER
NO LIABILITY FOR DROUGHT, ETC.

7. a. The United States shall furnish the District, the district water supply for each irrigation season during which this contract is in effect. After the District has satisfied its obligations to the United States under the terms of this contract and under the terms of any amendment to this contract, the District shall, upon advance payment of its proportionate share of the cost of operating and maintaining the reserved works, continue to be entitled to the operation of the reserved works for the purpose of furnishing the district water supply.

b. On account of drought, inaccuracy of distribution, or other causes, there may occur at times during any year, a shortage in the district water supply. In no event shall any liability accrue against the United States or any of its officers, agents, or employees for any damage, direct or indirect, arising out of such shortage; nor shall any obligation provided for herein be reduced because of any such shortage or damage. In any year in which such shortage may occur, the District shall, upon request of the contracting officer, provide a plan of equitable distribution of the district water supply among the District lands.

POINTS OF DELIVERY, MEASUREMENT, AND RESPONSIBILITY FOR DELIVERY OF WATER

8. a. Water to be furnished to the District pursuant to this contract shall be delivered at the Willwood diversion dam or at such point as may be varied in the discretion of the contracting officer.

b. The United States shall not be responsible for the control, carriage, handling, use, disposal, or distribution of water which may be furnished the district hereunder beyond the point of delivery as provided in (a) of this Article, and the District shall hold the United States harmless on account of damage or claim of damage of any nature whatsoever for which there is legal responsibility, including property damage, personal injury, or death arising out of or connected with the control, carriage, handling, use, disposal, or distribution of such water beyond said point.

c. The United States claims all of the waste, seepage, and return flow derived from water furnished pursuant to this contract, and the same is hereby reserved and retained by the United States.

PAYMENT OF DISTRICT CONSTRUCTION CHARGE OBLIGATION

9. a. The District assumes and agrees to pay to the United States, in the manner hereinafter stated, a contruction charge obligation of One Million Five Hundred Thousand Dollars ($1,500,000). This construction charge obligation shall cover

(1) expenditures by the United States of funds heretofore appropriated by Congress for the construction of the district irrigation works;

(2) expenditures by the United States of funds appropriated by Congress for the completion or rehabilitation of irrigation works serving the Willwood Division and the lands under the district, it being understood that such expenditures shall be for works or for the rehabilitation of works which the Secretary may find to be necessary and the construction or rehabilitation of which is approved by the District's Board of Commissioners;

(3) any deficit which the United States has incurred or shall incur as the result of operating and maintaining the district irrigation works; and any delinquent water rental charge including interest and penalty thereon;

(4) the book value (cost minus depreciation) of the operation and maintenance equipment and supplies transferred to the District in accordance with Article 10f below:

Provided, That should the above expenditures and charges by the United States be less than One Million Five Hundred Thousand Dollars ($1,500,000) because of failure of Congress to appropriate funds or for other cause, then the District shall pay a construction charge obligation equal only to the amounts actually expended and charged by the United States for the purposes above outlined.

b. Such construction charge obligation shall be paid in successive annual installments until the full amount of the obligation has been paid. The first half of each such annual installment shall be due and payable on or before January 31, beginning with the year 1951. The second half of each such annual installment shall be due and payable on or before May 31, beginning with the year 1951. The annual installments shall each be $27,400 until the full amount due under this contract has been paid: Provided, that the District may elect to pay annual installments in accordance with a variable formula as described below in (c).

c. On or before February 15 of any year after the first year and during the term of this contract the District Board of Commissioners, after being duly authorized by a majority vote of the District's electors, may notify the Secretary in writing that, beginning with the next succeeding calendar year, the District elects to make payment of its annual installments in accordance with a variable formula: Provided, That once the District Board of Commissioners notifies the Secretary of the District's election to make payment in accordance with a variable formula, all annual installments thereafter shall be paid in accordance with such variable formula. On March 15 of the year in which the Secretary receives notice of such election by the District, and on March 15 of every year thereafter during the term of this contract, the Secretary shall announce the amount of the annual installment which shall be due in the succeeding year. The amount of each annual installment payable under this subsection (c) shall be determined by multiplying the product of the base charge and the price index factor by the agricultural parity ratio:

(1) The "base charge" shall be $24,600.

(2) The "price index factor" is that number which represents the relationship between the current prices received for farm products and the average prices received for farm products during the period 1939-1944 as determined by the Secretary.

(3) The "agricultural parity ratio" is the national agricultural parity ratio as conclusively determined by the Secretary for the year preceding the notice year.

(4) In making the determinations required in (c) (2) and (c) (3) above the Secretary shall use the commodity price indexes and the national agricultural parity ratio as determined by the Secretary of Agriculture under the provisions of Title II of the Agricultural Act of 1948 (Public Law 897, 80th Cong., 2d Sess.), as it may be amended from time to time. If the commodity price indexes and national parity ratio, which are basic to the determination of the annual installment under (c) of this Article, are not avail-

able for any year the annual installments due under this contract shall be $24,600.

d. Annual installments under subsection (c) above shall be not more than one hundred seventy-five percent (175%) of the base charge and not less than fifteen percent (15%) of the base charge.

OPERATION AND MAINTENANCE OF DISTRICT IRRIGATION WORKS

10. a. On January 1, 1950, the United States will transfer to the District and the District will accept the care, operation, and maintenance of all of the district irrigation works described in Article 5f.

b. From and after January 1, 1950, the District shall care for, operate and maintain the district irrigation works without cost or expense to the United States and in full compliance with the Federal Reclamation Law, the rules and regulations of the Secretary pursuant thereto, and the terms of this contract. The District's care, operation, and maintenance of the district irrigation works shall be subject to the supervision of the contracting officer, and shall be in a manner that will insure that such works shall remain in as good condition and of equal capacity for the distribution and supply of irrigation water as on the date of this transfer.

c. No substantial change will be made by the District in any of the district irrigation works without first obtaining written consent of the Secretary. The District shall make promptly any and all repairs to the district irrigation works, which, in the opinion of the Secretary, are necessary. If, in the opinion of the Secretary, any part of the district irrigation works is for any cause unfit for service, he may order the water shut off and turned out until, in his opinion, such part of the works is put in proper condition for service. In case of neglect or failure of the District to make such repairs, the Secretary may cause the repairs to be made and the cost thereof, as determined by the Secretary, shall be paid by the District to the United States as provided in Article 12.

d. After the District shall have taken over the care, operation, and maintenance of the district irrigation works, the Secretary shall cause to be made, from time to time, reasonable inspections of such works. The actual costs of such inspection, as determined by the Secretary, shall be paid by the District to the United States as provided in Article 12.

e. In the event the District is at any time in default of any of its obligations to the United States under this contract, or is found by the the Secretary to be operating the district irrigation works, or any part thereof, in violation of the provisions of this contract, then at the election of the Secretary, the United States shall take over from the District the care, operation, and maintenance of the said works, by giving written notice to the District of such election and of the effective date thereof. Thereafter during the period of Government operation the District shall pay to the United States the cost of operation and maintenance of the district irrigation works, as provided in Article 12. Payment shall be in advance of the delivery of water. Such works or any part thereof may be re-transferred to the District, at the election of the Secretary, in the manner as originally transferred to the District. The District shall surrender possession and accept the re-transfer on being given the notice provided for herein.

f. The United States will turn over to the District at book value (cost minus depreciation) the O&M equipment and supplies as shown on the "O&M Equipment & Supply List" which is hereto attached as Exhibit B and by this reference made a part hereof.

The amount of the book value of such equipment and supplies shall be charged to the District as above provided in Article 9a.

g. Title to the district irrigation works shall be and remain in the United States until the construction charge obligation of the District as prescribed in Article 9 has been fully discharged and until otherwise provided by Congress, notwithstanding that such works are transferred to the District for care, operation and maintenance.

O&M OF RESERVED WORKS

11. The United States shall retain the care, operation, maintenance, and use of the reserved works defined in Article 5g. The District shall pay its equitable share of the cost of operating and maintaining such works, as provided in Article 12.

NOTICE TO DISTRICT OF CERTAIN COSTS AND PAYMENT BY DISTRICT

12. a. On or before April 1 of each year during the term of this contract, the Secretary shall notify the District of the following:

(1) The cost of such items for the administration, supervision, and general expenses which have been incurred during the preceding year in connection with the District irrigation works as in the opinion of the Secretary are properly and equitably chargeable to the District.

(2) The District's share of the cost of operating and maintaining the reserved works, which amount shall be the District's share of the estimated cost of operating and maintaining the reserved works during the current year, plus or minus any amount by which the District's payment of its share of the estimated cost for operating and maintaining the reserved works during the preceding year was respectively less or greater than the District's share of the actual cost of operating and maintaining the reserved works during the preceding year.

(3) The cost of any repairs made pursuant to subarticle 10(c); the cost of any inspections made pursuant to subarticle 10(d); and the estimated amount of any operation and maintenance costs to be incurred by the United States pursuant to subarticle 10(e).

b. The District shall make payment to the United States of the costs stated in such notice on or before May 1 following.

RESERVE FUND FOR OPERATION AND MAINTENANCE

13. During the year 1949, the District shall levy assessments, tolls, or other charges against the lands of the District sufficient to enable the accumulation from such levy of a reserve fund of $27,400 to be maintained by the District apart from its other funds, to be available, subject to the approval of the Secretary, only for the purpose of meeting major unforeseen costs of operation and maintenance, repair, and betterment of the distribution works. Thereafter, such further amounts, not to exceed Six Thousand Dollars ($6,000), shall be collected whenever, as of the time the annual operation and maintenance charge is levied by the District, the reserve fund has been reduced below Twenty Thousand Dollars ($20,000) and until the fund has again been increased to $27,400.

AGREED CHARGES A GENERAL OBLIGATION OF THE DISTRICT BUDGET AND ASSESSMENT ROLL TO BE APPROVED BY SECRETARY

14. The District as a whole is obligated to pay to the United States the charges becoming due as provided in this contract, notwithstanding the individual default in the payment to the District by individual water users of assessments, tolls, or other charges levied by the District. The District will cause to be levied and collected all necessary assessments, tolls and other charges, and will use all of the authority and resources of the District to meet the obligations of the District to make in full all payments to be made pursuant to this contract on or before the date such payments become due and to meet the other obligations under this contract. Each year during the term of this contract, the District shall secure the Secretary's approval of its budget, prior to filing the same in the office of the District Court, as required by Section 71-824 of Wyoming Compiled Statutes, 1945. The District shall likewise, in each year during the term of this contract, secure the Secretary's approval of its assessment roll prior to filing the same in the office of the County Commissioners, as required by Section 71-826 of Wyoming Compiled Statutes, 1945.

CONSTRUCTION CHARGES MAY BE ASSESSED IN ACCORDANCE WITH LAND CLASSIFICATION

15. a. It is understood and agreed that any of the District's assessments, tolls or other charges against individual tracts in the District for the purpose of paying the District's construction charge obligation, as provided above in Article 9, may be based on the classification or reclassification of such tracts under subsection 4D of the Fact Finders' Act of December 5, 1924 (43 Stat. 672, 702), as supplemented by Section 8 of the Reclamation Project Act of August 4, 1939 (53 Stat. 1187), or as hereafter amended. The construction costs heretofore apportioned against each tract, in accordance with such a classification, have been announced in Shoshone Public Orders Nos. 38, 40, 41, 43, 46, and 48.

b. Upon any complete reclassification of the District lands, each tract of productive land may be placed into one of four paying classes. Thereupon, differing assessments, tolls or other charges against individual tracts in the District for the purpose of paying the District's construction charge obligation may be fixed for the different classes of land at such ratios as may be agreed to between the Secretary and the District's Board of Commissioners. The reclassification of District lands requested by the District February 20, 1948, and completed November 23, 1948, is hereby approved by the Secretary. The approved reclassification of each tract of the District lands is set forth on the Land Classification list which is hereto attached as Exhibit A and by this reference made a part hereof.

PENALTY FOR DELINQUENT PAYMENTS

16. Every installment or charge required to be paid to the United States under this contract and which shall remain unpaid after it shall have become due and payable shall be subject to a penalty of one-half of one percent per month from the date of delinquency. The District shall impose on delinquencies in the payments of assessments, tolls, or other charges levied by the District to meet its obligations under this contract, such penalties as it is authorized to impose under the laws of the State of Wyoming.

PUBLIC LAND SUBJECT TO ASSESSMENTS UNDER THE SMITH ACT

17. Pursuant to the provisions of ~~Action~~ Section 3 of the Act of Congress of May 15, 1922 (42 Stat. 541), all unentered public lands and entered lands for which no final certificate (Bureau of Land Management Form No. 4-196 or comparable document) has been issued, located within the District, and described in Exhibit A, attached hereto and made a part hereof, are hereby designated as subject to the provisions of the Act of Congress of August 11, 1916 (39 Stat. 506): *Provided*, That unentered public land, while in that status, shall not be assessed by the District for any purpose, except that lessees thereof may be required to pay a water rental charge for water requested by such lessees.

CARRYING OUT OBLIGATIONS OF CONTRACTS

18. The District shall carry out, in accordance with their correct intent and meaning, and to the satisfaction of the Secretary, all Shoshone Project contracts, of whatever kind or nature, now in force (or hereafter in force, provided any such new contracts or any modification of existing contracts are acceptable to the District Board, as shown by a resolution of the Board duly adopted) affecting the transferred property in any manner and shall fulfill all obligations imposed upon the United States therein. No contract affecting the project made by the District, except for the usual labor, equipment, supplies and services in connection with the operation and maintenance of the transferred works, and the delivery and distribution of water, shall be valid until approved by the Secretary, and a draft of such contract shall be submitted to the Secretary for approval as to form before execution.

DEFAULTS

19. All benefits to accrue to the District or to persons or lands in the District under the terms of this contract are conditioned upon payment to the United States of the charges provided in this contract, in accordance with the terms and conditions herein set out.

a. Should the District fail to levy the assessments, tolls or other charges against any tract of land in the District required to be levied to meet the District's obligations to the United States under this contract, or having levied, should the District be prevented from collecting such assessment, tolls or other charges by any judicial proceeding, or otherwise fail to collect them, no such tract of land shall be entitled to receive water.

b. No water shall be furnished to the District by the United States or by the District through the district irrigation works or otherwise to or for the use of persons or lands therein during any period in which the District may be

(1) In arrears in the payment to the United States of any charge required to be paid under Article 12 of this contract;

(2) more than twelve months in arrears in the payment to the United States of any installment on its construction charge obligation required to be paid under Article 9 of this contract.

c. No water shall be furnished by the District, through the district irrigation works or otherwise, to any persons or lands therein which may be in arrears in the payment to the District of any assessments, tolls or other charges levied or established by the District for the purpose of raising revenues to meet the payment by the District to the United States of any of the District's obligations under this contract.

d. No waiver at any time by the United States of its rights with respect to default or any other matter arising in connection with this contract shall be deemed to be a waiver with respect to any subsequent default or matter. All rights of action for breech of this contract are reserved to the United States as provided in Section 3737 of the Revised Statutes of the United States, as amended (41 U.S.C. 15).

APPLICATION OF PAYMENTS

20. The United States may, at its option exercised by the Secretary, apply any payment or part thereof by the District to the United States to any charges then due and payable by the District to the United States under the provisions of this contract.

SELECTION OF MANAGER AND SECRETARY

21. While the operation and maintenance of the district irrigation works is the obligation of the District, the District shall employ, at a compensation which in the opinion of the Secretary is adequate, a competent and suitable manager or superintendent, and a competent and suitable secretary. The selection of such manager or superintendent, and secretary shall be subject to approval by the Secretary; and upon notice from the Secretary that such superintendent is or has become unsatisfactory, the District shall promptly terminate the employment of such superintendent or secretary, and employ a superintendent or secretary who, in the opinion of the Secretary, is competent and suitable.

EXCESS LANDS

22. After the District takes over operation and maintenance hereunder, the District will not deliver water to irrigable lands then held by any one person in excess of 160 acres. The District, however, will assess such excess lands in the same manner and to the same extent as irrigable lands of the project to which water is furnished, are then being assessed.

COMPUTATION OF COSTS

23. The costs which make up the various charges to be paid by the District to the United States under this contract shall embrace all expenditures of whatsoever kind in relation to the function for which the charge is made, including, but without limitation by reason of this enumeration, the cost of surveys and investigations, labor, property, material and equipment, engineering, legal, superintendence, administration, overhead, general expense, inspections, special services, and damage claims of all kinds. The Secretary's determination as to what costs are properly chargeable under this contract and the amount and classification thereof shall be conclusive.

DISTRICT TO KEEP BOOKS AND RECORDS AND REPORT CROP AND OTHER DATA

24. To such extent and in such manner and form as may be prescribed by the Secretary, the District shall establish and maintain account and other books and records and furnish to the Secretary reports and statements as to information contained therein pertaining to (a) accounts and financial transactions of the District, (b) crops raised and agricultural or livestock products produced on the lands within the District, and (c) irrigation water supply and the disposition thereof, a report thereon to be furnished to the Secretary annually on or before December 31, or such other date or dates as may be fixed by the Secretary.

ACCESS TO BOOKS AND RECORDS

25. Each party shall have the right, during office hours, to inspect and to make copies of the other party's books and official records relating to matters covered by this contract.

RULES AND REGULATIONS

26. There is reserved to the Secretary the right so far as the purport thereof may be consistent with the provisions of this contract and the Reclamation Laws, to make rules and regulations and to issue directives to the District, and to add to and modify them as may be deemed proper and necessary to carry out the Reclamation Laws and this contract, and to supply necessary details of its administration, and the District agrees to observe such rules, regulations, and directives. To prevent the excessive and wasteful use of water by individual water users, the Secretary may hereunder require the District to make a special charge for water used in excess of an amount per acre to be fixed by the Secretary, the amount of such charge to be approved by the Secretary.

CONTINGENT ON APPROPRIATIONS OR ALLOTMENTS OF FUNDS

27. The expenditure of any money or the performance of any work by the United States herein provided for, which may require appropriations of money by Congress or the allotment of funds, shall be contingent on such appropriations or allotments being made. The failure of Congress to appropriate funds, or the failure of any allotment of funds shall not, however, relieve the District from any obligations theretofore accrued under this contract, nor give the District the right to terminate this contract as to any of its executory features. No liability shall accrue against the United Sotes in case such funds are not appropriated or allotted.

ASSESSMENTS FOR BENEFITS AND CONSTRUCTION AGAINST INDIVIDUAL TRACTS OF LAND IN THE DISTRICT DISPENSED WITH - ASSURANCES RELATING TO VALIDITY OF CONTRACT

28. a. Pursuant to the provisions of Section 71-1002 of Wyoming Compiled Statutes, 1945, it is expressly agreed that the assessment or assessments for benefits and construction against individual tracts of land in the District, heretofore required under the laws of Wyoming, are hereby dispensed with.

b. The execution of this contract shall be authorized by a vote of qualified electors of the District present and voting at an election held for that purpose as provided by law, and thereafter if the electorate of the District vote their approval of this contract, the Board of Commissioners of the District will file in the District Court of Park County, Wyoming, a petition praying, in effect, that this contract and the proceedings leading up to the execution of the same, and the assessments for benefits and construction, as required by this contract, may be examined, approved, and confirmed by the Court. The special proceedings herein agreed to be taken by the Board of Commissioners of the District shall in all things in manner and form be in strict compliance with the provisions of Section 71-1002 of Wyoming Compiled Statutes, 1945. The District shall furnish the United States for its files certified copies of all proceedings relating to the authorization of this contract.

CHANGES IN DISTRICT ORGANIZATION

29. While this contract is in effect, no change shall be made in the District, by inclusion or exclusion of lands, by proceedings to dissolve, or otherwise,

except upon the Secretary's written consent thereto.

NOTICES

30. Any notice authorized or required by this contract shall be deemed properly given, except where otherwise herein specifically provided, if mailed, postage prepaid, to the Regional Director, Region 6, Bureau of Reclamation, Billings, Montana, on behalf of the United States, and to the Secretary of the Willwood Irrigation District, Powell, Wyoming, on behalf of the District. The designation of the person to be notified or the address of such person may be changed at any time by similar notice.

ASSIGNMENT LIMITED - SUCCESSORS AND ASSIGNS OBLIGATED

31. The provisions of this contract shall apply to and bind the successors and assigns of the parties hereto, but no assignment or transfer of this contract, or any part thereof or interest therein, shall be valid until approved by the Secretary.

DISCRIMINATION AGAINST EMPLOYEES OR APPLICANTS FOR EMPLOYMENT PROHIBITED

32. The District shall not discriminate against any employee or applicant for employment because of race, creed, color, or national origin, and shall require an identical provision to be included in contracts relating to the performance of this contract. This provision, however, does not refer to, extend to, or cover the activities of the District which are not related to or involved in the performance of this contract.

OFFICIALS NOT TO BENEFIT

33. No member of or Delegate to Congress or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise herefrom, but this restriction shall not be construed to extend to this contract if made with a corporation or company for its general benefit.

IN WITNESS WHEREOF, the parties hereto have signed their names the day and year first above written.

THE UNITED STATES OF AMERICA
By William E. Warne
Assistant Secretary of the Interior

WILLWOOD IRRIGATION DISTRICT
By Ervel F. Jones
President

ATTEST:
Homer C. Mann (SEAL)
Secretary

FEDERAL REGISTER
VOL. 48, NO. 68, APRIL 7, 1983

NOTICE OF PROPOSED RULEMAKING
FEDERAL POWER ACT
31 MARCH 1983

AGENCY: FERC, DOE

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Date

Address

For Further Information Contact

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and order are effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674).

The proposal invited written comments on changing § 993.172 (b) and (d) until February 28. Six comments were received from affected handlers opposing the proposal. These handlers expressed concern that changing the time requirements for filing the reports from the 10th calendar day of the next succeeding month would impose additional burdens on their business operations, but would not contribute significantly to the intended objective of enabling the PMC to issue its statistical reports sooner each month. Another comment would have given handlers additional time to file these reports, but not sufficient time to lessen the additional burdens expressed by commentators.

After consideration of all relevant matter including the comments received and the benefits that would accrue to the prune industry from the proposed change in reporting the required information, it is determined that the additional burden imposed on handlers would not warrant changing the time requirements for filing the supply and shipment reports.

Therefore, the current time requirements in § 993.172(b) for filing the monthly "new Crop Supply and Inbound Prune Report", and in § 993.172(d) for filing the monthly "Report of Shipments" tend to effectuate the declared policy of the act and shall remain in effect.

List of Subject in 7 CFR Part 993

Marketing agreements and orders, Plums and Prunes, California.

(Secs. 1–19, 48 Stat. 31, as amended; 7 U.S.C. 601–674)

Dated: April 4, 1983.

D. S. Kuryloski,

Deputy Director, Fruit and Vegetable Division.

[FR Doc. 83-9122 Filed 4-6-83; 8:45 am]

BILLING CODE 3410-02-M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 4 and 11

[Docket No. RM83-13-000]

Annual Charges for Use of Government Dams and Other Structures Under Part I of the Federal Power Act

March 31, 1983.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to amend the regulations governing annual charges for hydroelectric power projects that use Government dams and other structures. The Commission currently determines these annual charges on a case-by-case basis. The proposed rule would adopt a generic, formula-based approach. The Commission proposes to apply the rule to newly-licensed projects, projects with licenses that indicate annual charges will be determined by this rulemaking, relicensing of projects, and readjustments of projects annual charges.

The Commission expects this proposed rule to provide a means to estimate, with reasonable precision, the true economic benefits of a hydro project at a Government dam. Those benefits, after being converted to a constant dollar amount, would be shared equally by the licensee and the United States. The proposed rule also seeks to avoid increasing the costs borne by consumers of electric power.

The rule is expected to reduce the time and resources now needed by the Commission, licensees, and other persons to fix annual charges under the current case-by-case approach. In addition, the overall process for licensing these projects should be expedited.

DATE: Comments must be received on or before May 16, 1983.

ADDRESS: Comments must be submitted to Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should refer to Docket No. RM83-13-000. An original and 14 copies must be filed.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

I. Introduction

The Federal Energy Regulatory Commission (Commission) proposes to amend the regulations governing annual charges for hydroelectric power projects that use Government dams and other structures. These annual charges are assessed under section 10(e) of the Federal Power Act (FPA).[1] Section 10(e) empowers the Commission to fix reasonable annual charges for the "use, occupancy, and enjoyment" of Government property, including dams and other structures owned by the United States.

The Commission currently determines annual charges on a case-by-case basis. The charge is based upon a "sharing of the net benefits" realized by a licensee from using a Federal dam or other structure.

Measurement of project "net benefits" is, therefore, the critical and fundamental task that lies at the heart of this approach. And, just as important to recognize, measurement of project net benefits is a complex matter. Stated as simply as possible, "net benefits" are the difference between (1) the estimated value of the power produced at the project (equal to the cost of producing equivalent power with the least costly alternative sources of power) and (2) the estimated costs of producing project power.

The Commission has, in exercising the discretion granted in section 10(e), historically split the net benefits equally with a licensee. A licensee pays to the Commission 50% of the estimated net benefits as its annual charge under section 10(e).[2] Payments are made in uniform annual amounts over the term of the project license,[3] unless the annual charge is readjusted under the provisions of section 10(e).[4]

A. Summary of Proposed Method

The Commission proposes to replace the present case-by-case calculation of annual charges under 18 CFR 11.22 with a generic, formula-based approach. This rule would apply to all projects that become available for service (i.e., construction is complete) after the effective date of the final rule or that have licenses which indicate the annual charge will be the amount determined by this rulemaking.[5] This rule would also apply to any readjustments of an annual charge and to relicensing of a project using a Federal dam. The annual charges for pumped storage projects using Federal dams would not be subject to this rule.

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[1] 16 U.S.C. 803(e) (1976).

[2] Section 17(a) of the Federal Power Act, 16 U.S.C. 810(a) (1976), provides that these funds shall be paid into the United States Treasury, subject to certain percentage distributions specified in section 17(a).

[3] The annual dollar amount now collected is the same each year since the total estimated net benefits over the license term have been levelized into equal annual amounts.

[4] Pursuant to section 10(e), an annual charge may be readjusted by the Commission at the end of twenty years after the project is available for service and at periods of not less than ten years thereafter upon notice and opportunity for [illegible] See generally, Montana Power Co. v. FPC, 459 F. 2d 863 (D.C. Cir. 1972), cert. [illegible] 650 (1972).

As discussed more fully in Section III of this Notice, the proposed method retains the concept of "net benefits" as the basis for setting the annual charge. The two parts of the net benefits calculation would still be the fundaments—finding the cost of power from the least costly alternative sources ("power value") and finding the cost of project power. The proposed rule would, however, use regional estimates for the power value component, not project-specific estimates. In addition, the proposed rule would not use estimates for project construction costs in determining project power cost but, instead, would use actual construction costs as verified by the developer after construction is complete.

These two changes from the presently used method are very significant. The regional power value estimates, focusing on the least costly alternative sources of power in the region, would be based upon standard formulas; standard procedures; Federal data on fuel costs, interest rates, and wage rates; and other published or readily available utility cost data. Under the proposed method, the power value calculation is generalized in that it uses average fuel cost data, average costs of financing, and average investment costs for alternative sources of power, such as baseload coal plants. The electric utility data will be that which is collected and published by recognized sources, such as the Energy Information Administration of the United States Department of Energy.

The estimate of project power costs—the other half of the net benefits equation—would be based upon actual construction costs plus an estimate of operation, maintenance and administrative (O&M) costs for the project. Using actual project costs will eliminate the uncertainties associated with using estimated project construction costs. Project O&M costs, however, necessarily must be estimated. Standard formulas and industry data, specified more precisely in Section III, *infra*, will be used for these O&M cost estimates.

Net benefits will be the difference between the appropriate regional power value and the estimated project power costs (based upon actual construction cost but estimated O&M costs). The power values for the year of project completion and for the region in which the project is located will be applied. Both power values and project power costs will be levelized[6] over the period of time extending from the year the project is available for service until the end of the term of the project license. The net benefits determined from these power values and project power costs will be stated in dollars of the year in which project construction is completed. The annual charges for a project will be calculated immediately following the year in which project construction is completed.

Once the annual charge, sometimes referred to as a "use charge," is established, the charge will be fixed in constant dollars over the remaining term of the project license unless a readjustment is made at a statutorily-prescribed time. The actual annual payment amount will be adjusted for inflation using the Gross National Product (GNP) Deflator.[7] This will keep the relative value of the charge vis-a-vis the project benefits at a constant level.

The Commission will update regional power value data annually by notice in the Federal Register. This notice will also specify the GNP Deflator factor that will be applied for the year's annual charges billings. Yearly updates of regional power value data in subsequent years will not affect the anuual charges established for any project completed in an earlier year

B. Objectives and General Considerations

The proposed generic method is intended to estimate, with reasonable precision, the true economic benefits of a hydro project at a Government dam. In trying to estimate the economic worth of the project, it is appropriate to consider electricity value indicators such as levels and trends of fuel prices and costs of electricity from other generation sources in the general locale of the project. This is a basic aspect of the power value formulas in this Notice. Estimates of the costs of producing project power can be based on the costs of construction, financing, operation, maintenance, and project output. The value of project power depends significantly on its effective capacity during the peak electric load season, its annual energy production, and the projected regional market for electric power.

The Commission believes that the proposed methodology for estimating net benefits parallels the evaluation process that an experienced developer would use, that is, it develops an estimate of value of project power output over the term of the license and an estimate of the specific project power costs. Thus, the Commission expects this proposed rule to allow a reasonable and fair approximation of the economic benefits of each project. This will enable the Commission to fix "reasonable" annual charges as mandated by section 10(e) of the FPA.

This methodology, imposed on a generic basis, will reduce the time and resources now needed to fix annual charges under the current case-by-case approach. Licensees will directly benefit from the elimination of the litigation burden that has, at times, accompanied the setting of annual charges for a project. In addition, the overall process for licensing hydro projects at Government dams will be expedited, thereby benefitting project developers. By eliminating the need to estimate project construction costs, the accuracy of calculating net benefits should improve. This will aid in improving the degree of financial predictability for potential developers. In addition, the use of estimated regional power values on a generic basis will eliminate some of the problems of the current approach, such as the variation in assumptions and estimates among various individual licensing cases. In particular, the proposed indexing of annual charges to the GNP will remove the need to estimate future inflation trends when estimating project net benefits. Thus, the ed rule should increase the ative uniformity of annual charges.

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[5] Projects may consist of more than one generating unit, and these individual units may become available for service at different times. The project net benefits will be reevaluated as each unit becomes available for service. However, since the term of the project license normally remains unchanged even though new units may be added on, the period of time over which the net benefits will be levelized will still be from the time each unit is available for service until the end of the license term. *See* note 6, *infra*. If an added unit so substantially changes the project that issuance of a new project license is deemed necessary, the net benefits will be determined over the new license term.

[6] "Levelized" means determining a series of uniform annual amounts which, over a specified period, would result in the same aggregate present value as a series of varying, estimated annual amounts. The concept of using levelized annual costs and benefits as a means of comparing alternatives is discussed in standard texts, such as Grant and Ireson, *Principles of Engineering Economy* (5th ed. 1970).

[7] This is published annually in the Annual Report of the Council of Economic Advisers. The Commission believes that using the GNP Deflator is appropriate, given the nature of this rulemaking. The Consumer Price Index (CPI), as used in Portland General Electric Co., 20 FERC ¶ 61,294 (Sept. 1, 1982), is believed less appropriate for this generic approach because the CPI does not focus comprehensively on the overall economic value of all goods and services across the country.

Finally, the Commission is fulfilling the mandate of section 10(e) of the FPA to seek to avoid any unwarranted increase in the cost of electric power for consumers. By determining net benefits on a project-specific basis using regional power values, the Commission is attempting to provide a means to consistently and uniformly determine the true benefit of a project. Undervaluation of a project's net economic benefits might reduce electric rates for ratepayers receiving power at cost from a specific project. However, the resulting, overly low annual charge payment to the United States Treasury ultimately places higher costs on other consumer members of the public, who must make up the difference through their taxes. Thus, the proposed rule strikes an even-handed balance between these different consumer and taxpayer interests by standardizing a fair charge-setting process, by determining net benefits based upon the true economic value of the project, and by collecting 50% of those net benefits for the United States.[8]

II. Background

A. Section 10(e) of the Federal Power Act

Under section 10(e) of the FPA, the Commission is directed to fix a reasonable annual charge recompensing the United States for the use of Federally-owned dams and other structures.[9] The charge must be set within certain constraints: The charge must be greater than zero, the charge must reimburse the Government in proportion to the value of using the dam, and the charge should seek to avoid increasing the price of power to consumers.[10] Section 10(e) also allows the Commission to readjust the annual charge at specific times beginning in the 20th year after the project is ready for operation. Readjustments can be made only after notice and opportunity for hearing.

B. Legislative History

The legislative history reveals that Congress believed that the use of a Government dam is a benefit conferred on the licensee.[11] Although the legislative history contains discussjon of different methods of assessing the charges, these methods all related to sharing the benefit a licensee receives from use of Federal property.[12] Thus, the legislative history indicates strongly that the Commission should make annual charges proportional to the benefit conferred.[13]

The legislative history also shows that the Commission has discretion to revise the charges to keep them proportional to the benefit conferred. This is embodied in the readjustment provisions of section 10(e). Congress also indicated that the Commission could establish a formula charge which would change annual charges more frequently than at the times specified for readjustment.[14] The Commission has considered the use of such formula-based charges in the past.[15]

C. Implementation of Section 10(e)

Beginning in the early 1920's, the Commission assessed, on a case-by-case basis, annual charges that were proportional to the value of the project to the licensee. Although a number of approaches have been used since the 1920's, the method currently used in most cases has been "sharing of the net benefits" (SND).[16] The SNB method consists of four steps: (1) Finding the annual cost of power from the least expensive alternative source (power value); (2) finding the annual cost of project power (project powerhouse costs); (3) finding the net benefits by subtracting power cost from power value; and (4) charging the licensee for 59% of the net benefit. The Commission has customarily written the annual charge amount into each license. The annual charge remains unchanged unless it is readjusted at the times specified in section 10(e).

The Commission's implementation of section 10(e) through the SND method was upheld in the *City of Vanceburg v. FERC*.[17] The *Vanceburg* opinion cites the legislative history of the Act as suggesting that "reasonable" charges should be proportional to the Federal benefits conferred. Even though the *Vanceburg* opinion approves the SNB method, the court does not restrict the Commission to that method alone. The court found that the Commission has discretion, within the statutory language, to use any one of several methods in calculating the charge, so long as the basis of the charge is the "actual value of dam use to the specific licensee."[18] The court indicated it would defer to any method selected by the Commission as long as the charge is greater than zero, is based on the full value of using the Government dam, seeks to minimize consumer cost, and encourages hydropower development.[19]

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[8] The Commission wishes to emphasize that nothing in this Notice of Proposed Rulemaking should be taken as an indication of the Commission's views on establishing avoided cost rates under the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645.

[9] Section 10(e) states in pertinent part:

"That the licensee shall pay to the United States reasonable annual charges in an amount to be fixed by the Commission * * * for recompensing it for the use, occupancy, and enjoyment of its lands or other property; and for the expropriation to the Government of excessive profits until the respective States shall make provisions for preventing excessive profits or for the expropriation thereof to themselves, or until the period of amortization as herein provided is reached, and in fixing such charges the Commission shall seek to avoid increasing the price to the consumers of power by such charges * * * *Provided*, That when licenses are issued involving the use of Government dams or other structures owned by the United States or tribal lands embraced within Indian reservations, the Commission shall, subject to the approval of the Secretary of the Interior in the case of such dams or structures in reclamation projects and, in the case of such tribal lands, subject to the approval of the Indian tribe having jurisdiction of such lands . . . , fix a reasonable annual charge for the use thereof, and such charges may with like approval be readjusted by the Commission at the end of twenty years after the project is available for service and at periods of not less than ten years thereafter upon notice and opportunity for hearing . . . but in no case shall a license be issued free of charge for the development and utilization of power created by a Government dam and that the amount charged therefore in any license shall be such as determined by the Commission.

[10] This proposed rule is not intended to apply to annual charges for non-Federal projects located on Indian lands. While the principles and consideration in this rulemaking may be useful on a case-by-case basis for such projects, a separate rulemaking will be necessary for non-Federal projects on Indian lands.

Section 10(e) mentions the phrase "subject to the approval of the Secretary of Interior" with respect to setting certain annual charges. As discussed more fully in Section V.H. *infra*, this phrase grants intervention and judicial appeal rights to the Secretary of the Interior. *See, e.g.*, Montana Power Co. v. FPC, 459 F.2d 863, 873–74 (D.C. Cir. 1972).

Section 10(e) also mentions a reasonable charge to recover excessive profits. This phrase was intended by Congress to apply to situations where state regulation of utilities and other project developers had not yet been imposed. *See* 59 Cong. Rec. 6524, 6528 (1920). Thus, this phrase has little, if any, application to the setting of annual charges at this time.

[11] *See* 54 Cong. Rec. 1185 (1917); 56 Cong. Rec. 9311–12, 9903–05 (1918); 58 Cong. Rec. 2135–38, 2222–24 (1919); 59 Cong. Rec. 1041, 1100–07 (1920).

[12] Among the methods suggested for computing annual charges were: (1) Percentage of licensee profits; (2) a flat rate per horsepower energy developed; and (3) percentage of the savings from choosing hydropower rather than an alternative fuel generating source. *See* note 11, *supra*.

[13] *See* note 11, *supra*; *see also*, 59 Cong. Rec. 6524–29 (1920). This reading of the legislative history is mentioned in City of Vanceburg v. FERC, 571 F.2d 630 (D.C. Cir. 1977), *cert. denied*, 439 U.S. 818 (1978); *see also* Montana Power Co. v. FPC, 298 F.2d 335 (D.C. Cir. 1962).

[14] 58 Cong. Rec. 2223 (1919); *see also* S. Rep. No. 180, 66th Cong., 1st Sess (1919).

[15] *See, e.g.*, Escondido Mutual Water Co., Opinion Nos. 36 and 36–A, 6 FERC ¶ 61,189 (Feb. 28, 1979), 9 FERC ¶ ——— (Nov. 26, 1979), *rev'd other grounds* Escondido Mutual Water Co. v. FERC, 692 F.2d 1223 (9th Cir., 1982), *rehearing denied*, March 17, 1983, Portland General Electric Co., 20 FERC ¶ 61,294 (Sept. 1, 1982).

[16] A few annual charges have been computed according to the "sharing-of-costs method," in which the annual costs of joint-use facilities (i.e., the dam and reservoir) are apportioned between the United States and the licensee in the ratio which the benefits of the facilities to the Government bear to the benefits of the facilities to the licensee. However, this method is no longer used.

[17] 571 F.2d 630 (D.C. Cir. 1977).

[18] 571 F.2d at 647. The court in Vanceburg also deferred to the Commission's discretion in

III. The Proposed Rule

A. Overview

1. Use of the Basic SNB Theory

The Commission is persuaded that the basic tenets of the "sharing of the net benefits" (SNB) method provide a reasonable foundation upon which to determine the economic resource value of a hydro project using a Government dam. As mentioned earlier, the SNB method has four basic steps:

(1) Determining the annual value of the power to be produced at the hydropower project over the license period (power value). This consists of estimating the cost of the least expensive, equivalent amount of power available from alternative sources;

(2) Determining the annual cost of producing power at the hydropower project over the license period;

(3) Finding the annual net benefit by subtracting the annual project power cost from the annual power value; and

(4) Dividing the annual net benefit equally between the licensee and the United States.

The proposed method follows this four-step process. However, unlike the current, case-by-case SNB approach that estimates all elements of the process on a totally project-specific basis, the proposed method determines net benefits for each project based upon actual project construction costs and estimated regional power values.

The use of estimated regional power values has certain aspects worthy of note. The selection of the regions will be based upon similarity of alternative power generation costs and projected regional fuel costs.[20] Annually, the Commission will publish a notice in the Federal Register that lists the year's power value data for each region. Also listed will be capital costs and heat rates of the alterative thermal power plants, the present cost of fuel, the projected real fuel price escalation, and the current and projected regional utility average incremental energy costs. The capital costs of regional steam plant alternatives will be determined from the Concept-5 power plant cost estimating code developed and maintained by the Oak Ridge National Laboratory.[21] The detailed assumptions used as code inputs will be listed.

A regional power value will be directly calculated by the formulas and data as a function of a project's annual capacity factor[22] and its peak season capacity factor.[23] A tabulation of sample power values for selected capacity factors will be included in the annual notice for ready reference.[24] Net benefit estimates, therefore, can be readily made by potential developers at any time, using their own project construction cost estimates and the power value data provided in the Commission's annual update notice.

Power value will be determined for the remaining term of the project license following the completion of construction, using present worth methods. The interest rate will be the real, "inflation-free" cost of money.[25] The power values will be developed and expressed in constant dollars as of the year of project completion.

For purposes of illustration only, this Notice contains power value and net benefit calculations, based upon 1982 data, for the New England and Wyoming regions. These sample caculations are presented in Section IV, *infra*. This illustration also demonstrates how a developer can use the published power value data and its own construction and O&M cost data to estimate what a project's annual charges will be.

2. Use of Standard Formulas and Data

The determination of power values is based on the procedures developed by the Commission, the Army Corps of Engineers, and other Federal water resource agencies to evaluate Federal power projects.[26] Section III.B, *infra*, includes a detailed description of the power value concept and its application under this proposed rule for determining net benefits of projects at Federal dams. Section III.B also explains the proposed power value formulas in detail.

Actual construction costs will be submitted by a developer after the project is completed. The Commission will use these actual costs in calculating net benefits and the actual annual charges. As mentioned earlier, estimates for project O&M costs will be made based upon standard data.[27]

The estimated net benefits determined under the proposed method represent the total benefits over the remaining period of the project license. The aggregate present worth[28] of the varying yearly amounts of benefits is levelized,[29] using the inflation-free discount rate, to establish an annual net benefit measured in constant dollars as of the year of project completion. This follows customary analytical techniques where the total stream of future benefits and costs is present-worthed to the start of project operation and then levelized.

3. Ownership Status of Licensee

The generalized net benefit determination method described in this Notice values the power produced by a hydropower project as equal to the cost of power from the least costly alternative source of power. This cost will depend, in part, on the financing costs of the alternative source of power and the taxes its owner must pay. Similarly, the calculation of the hydro project's power cost also depends, in part, upon the developer's financing costs and the taxes it must pay. Thus, it is clear that the amount of the net benefits and the annual charges will

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approving a method which assessed taxpaying entities a lower relative amount than comparable, non-taxpaying municipalities. The court said that merely because charges for municipal projects were proportionately higher than those assessed for similarly situated, investor-owned facilities does not necessarily mean that municipal licensees are being discriminated against. According to the court, the Commission may elect to consider or to ignore a licensee's taxpaying status when computing annual charges.

[19] *Id.*

[20] It is expected that 18–20 regions will be identified in the final rule.

[21] The Oak Ridge National Laboratory has published a user's manual for the Concept-5 program. C. R. Hudson II, *Concept 5 User's Manual* (ORNL-5470 January, 1979).

[22] Annual Capacity Factor (ACF) =

$$\frac{\text{Average annual generation (MWh)}}{\text{Installed capacity (MW) x Hrs. in year}}$$

[23] Peak Season Capacity Factor (PSCF) =

$$\frac{\text{Average generation in peak season (MWh)}}{\text{Installed capacity (MW) x Hrs. in peak season}}$$

The peak season capacity factor is a measure of the capacity available at system peak where the project operator does not control the storage and release of water for power production. This is normally the situation for non-Federal projects at Government dams.

[24] Section IV, *infra*, contains a partial example of how this tabulation would be presented.

[25] *See* Section III.B.3(b), *infra*.

[26] Federal Energy Regulatory Comm'n *Hydroelectric Power Evaluation* (DOE/FERC-0031 August, 1979); U.S. Water Resources Council, *Evaluating Hydropower Benefits* (Dec. 1981).

[27] *Id.*

[28] The present worth of a future benefit is the amount which, if invested at the cost of money, will yield the future benefit in the future year. The present worth technique reflects that a dollar tomorrow is worth less than a dollar today, even without inflation, because a dollar not spent can earn interest. This effect is also termed the "time value of money."

[29] *See* note 28, *supra*. Expressed another way, a "levelized" annual benefit or cost is a uniform annual benefit or cost amount which would provide the same lifetime sum of present worth values as the actual varying benefit or cost amounts.

depend upon whether the project developer is a public or private entity.

Financing costs and taxes appropriately corresponding to the licensee's ownership status will, therefore, be used in all power value and project power cost determinations to reflect more accurately the project's economic value. However, all illustrative examples in this Notice and in the sample regional power values to be published annually in the Federal Register will be based on public financing costs and the municipal and State exemption from taxes. This is to ease the burden of preparing these examples which are only illustrative of the net benefits determination. Public ownership status has been selected for these examples because it is expected that the great majority of licensees for power projects using Federal dams will be public entities.

4. Sharing of the Net Benefits

The Commission proposes to continue the current 50%–50% sharing of the net benefits for projects using a Federal dam or other structure. As discussed earlier in this Notice, the Commission is striking a balance between the overall public interest in collecting a fair payment for the benefits conferred upon licensees and the local electric consumers' interest in minimizing the cost of electricity from the project. Historically, the 50–50 sharing of the net benefits has proved to be equitable within the parameters of section 10(e) of the Federal Power Act.

While this Notice proposes to retain the 50-50 split, the Commission recognizes its statutory role to encourage small power projects. Projects of 5 MW or less in general and small projects that are economically marginal may require special consideration. The Commission, therefore, specifically invites comment on whether the 50-50 split should be applied to all projects or whether small projects should retain more than 50% of the net benefits, should be charged a flat fee, or should be exempted from annual charges.

B. Determination of Power Value

1. Background

The concept of power value was developed originally to determine the merit of proposed Federal hydropower projects. Federal agencies have used power values to evaluate Federal projects for economic feasibility and resource efficiency.[30] Power value is the estimated, levelized cost of the least costly alternative source of power that would be used in lieu of the hydro project power.

Some variation has historically occurred among the individual Federal agency attitudes toward certain elements, such as the appropriate fixed charge rate and the appropriate allowance for real fuel price escalation to be used. However, the same basic power value methodology has been widely used because it conveniently and reasonably compares alternatives.[31] The levelized annual cost approach reflects both the time value of money and the differing useful lives of alternatives. The cost of power from the least costly alternative is taken to be the power value of the hydro project power.

The proposed method for calculating power values is consistent with established hydropower project evaluation principles and employs the standard formulas and data elements used to determine the worth of Federal projects.

2. The Power Value Calculation

As noted earlier, the power value of a hydropower project represents the cost of equivalent wholesale electric power from the least costly alternative source or sources of power. Generally, power value consists of both a capacity value and and energy value component. The capacity value component reflects, as a consequence of building the hydropower project, the savings in annual fixed costs to a utility from the reduced need to obtain capacity from other sources to meet projected system load. The capacity value of a hydropower project is estimated in terms of the project's peak season capacity factor and the comparative reliability of hydro and thermal power sources.

The energy value component reflects the cost savings that result from producing hydroelectric energy at the project rather than obtaining equivalent energy from the least costly thermal alternative. The energy value component is determined as the net cost of supplying (a) the firm kilowatt hours of energy that would be produced by the equivalent thermal capacity [32] and (b) any additional non-firm energy produced.[33]

Power value is that combination of capacity and energy values, corresponding to a realistic regional alternative generation source, which provides the lowest total power cost. The capacity and firm energy values must be related to the same specific alternative source or sources of power. For example, the production cost (or energy value) of a baseload, coal-fired steam unit cannot be combined with the fixed cost (or capacity value) of a peaking, combustion turbine unit.

(a) *Capacity Value Component.* The capacity value of a hydropower project is the fixed cost of the thermal alternative, per kilowatt hour of generation, as expressed by the formula:[34]

$$CV = \frac{(I \times R) + FIC + FOC}{ACF \times 8760} \times 100 \times PSCF \times MAF$$

Where

CV = Levelized capacity value of the project (in cents per kWh) [35]

I = Investment (construction) cost of alternative generating unit completed in the same year as the project (in dollars per kW of capacity) [36]

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[30] *See* note 28, *supra*.

[31] Standard economic theory maintains that overall resource efficiency will be achieved by use of the lowest cost resource alternative, as long as the costs of all resources (goods and services) are established by a free market and not distorted by subsidies, price controls, or noncompetitive market characteristics.

[32] Firm energy is energy associated with reliable capacity.

[33] Non-firm energy is energy produced without reliable capacity.

[34] *Hydroelectric Power Evaluation, supra* note 28, explains the development of this expression, except for the final term. The MAF (Mechanical Availability Factor) is the ratio of the statistical mechanical availability of hydro generation versus thermal generation, excluding scheduled maintenance outages. It is expressed as:

$$MAF = \frac{1 - EFOR \text{ of hydro unit}}{1 - EFOR \text{ of thermal Unit}}$$

where EFOR is the equivalent forced outage rate. This is based upon the records of the North American Electric Reliability Council (NERC), *Generating Availability Data System Analysis and Reports*. The product of the MAF with the peak season capacity factor (PSCF) represents, as a portion of the installed hydro project capacity, the amount of thermal capacity which has the same load carrying capability as the hydro capacity. The capacity factor of the project during the peak load season (PSCF) represents the statistical hydrological resource availability as determined from records kept at Government dams. *See* note 23, *supra*.

[35] As discussed earlier, the levelizing factors are based on the "real" long-term interest rate and the resulting power values are expressed in dollars of the year of project completion.

[36] This number will be developed from the Concept 5 cost estimating guide, *supra* note 21, and

R = Annual fixed charge rate (decimal) [37]
ACF = Annual capacity factor of project (decimal) [38]
FIC = Annual levelized cost of fuel inventory (in dollars per kW of installed capacity) [39]
FOC = Annual levelized fixed operating costs for thermal alternative (in dollars per kW of installed capacity) [40]
PSCF = Capacity factor of project during peak load season [41]
MAF = Mechanical availability factor (decimal) [42]

The capacity factor during the system peak load season (PSCF) is determined by the hydrologic resource availability. Records exist for the monthly flows or releases from Federal dams. These records usually cover at least 15–20 years and can be used by a developer to calculate the average energy production expected at the project during the three-month peak load seasons (*i.e.*, usually June–August or December–February).

In calculating the PSCF factor, it is important to consider both winter and summer peaks and possible shifts of the season in which system peak occurs. The factor computed for the higher peak will be used unless the difference between the seasonal peaks is less than 3 percent in any year. In that case, the smaller seasonal factor will be used because load growth and changes in load composition could more easily shift the peak from one season to another during the term of the license. Therefore, the lower capacity factor would be more apropriate for determining the capacity value for the project.

(b) *Firm Energy Value Component.* The firm energy value of a hydropower project is the value of energy associated with the project capacity value. It is measured as the direct production cost of generating power by the most likely thermal alternative source. The amount of project firm energy may not exceed the alternative's maximum expected annual production. The value of each kilowatt hour of firm energy is expressed by the formula:[43]

$EV_f = F \times HR \times 10^{-6}) + O\&M + EV_a$

Where

EV_f = Levelized from energy value (in cents per kWh)
F = Levelized cost of fuel (in cents per million Btu) [44]
HR = Unit heat rate (Btu per kWh) [45]
10^{-6} = Conversion factor
O&M = Levelized variable operating and maintenance costs (in cents per kWh) [46]
EV_a = Energy value adjustment [47]

(c) *Non-Firm Energy Value Component.* Non-firm energy is that project energy not associated with capacity value. If represents energy produced at uncertain times, depending on water availability. Numerically, it is the excess of project annual energy production (if any) beyond the firm energy produced. It is valued at the incremental cost of wholesale energy in the region where the hydro project is located. This cost is also known as a utility's or power pool's "running cost" or "system lambda."

To obtain a levelized value for the non-firm energy, it is necesssary to estimate the trend of utility running costs in the region over the term of the license. This involves consideration of a region's generation mix. Analysis of data filed with the Commission under 18 CFR Part 290 indicates that utility systems with the optimum economic generation mix (essentially all coal except for peaking units) have average running costs approximately 20–30 percent above the production costs of their most efficient baseload units. Other systems, with significantly non-optimum generating mixes, (large amounts of oil and gas-fired baseload and intermediate generation) exhibit running costs up to 500 percent above baseload coal production costs. These latter systems are likely to correct this imbalance in generating mix in future years through additions or more economic capacity. However, the rate at which corrections can be made is constrained by sunk investment costs and the rate of system load growth.

At industry projected growth rates of 2–3 percent per year, the total installed capacity in the United States will double in the next 25–35 years. With service lives of thermal generating units averaging 30–40 years, there will be substantial replacement of existing capacity following the year 2000. A reasonable assumption, therefore, is that most utilities will be successful in correcting uneconomic generation mixes by the year 2020, but can make little changes before 1990.

Consistent with this evaluation, the proposed rule assumes that running costs of non-optimum systems, in constant dollars, will be unchanged up to 1990. Between 1990 and 2020, their constant dollar running costs are assumed to decline linearly to a level of 1.2 times baseload coal production costs in the year 2020. That level is then assumed for all years after 2020. The running costs of optimum systems are assumed to be 1.2 times baseload coal production costs in all years.

After establishing the system running costs in each year, the levelized non-firm energy value is obtained in the usual manner by present-worthing the running costs for each remaining year of the license, and then levelizing with the appropriate zero-inflation interest rate.

Thus, non-firm energy values are calculated as follows:

$$EV_{nf} = L \times \sum_{n=1}^{N} \times EV_n$$

Where

EV_{nf} = Levelized non-firm energy value, per kWh of non-firm energy (in cents per kWh)
L = Levelizing factor (also known as capital recovery factor)
EV_n = Present worth of energy value (running cost) in year n (in cents per kWh)
n = year, beginning with project completion year
N = total years from year that project is available for service to end of license term

(d) *Formula for Total Power Value.* The total power value is the sum of the capacity value component and the firm and non-firm energy value component. This is determined by applying the appropriate energy quantities to the firm and non-firm energy values.

(a) If there is only firm energy [Z>1.00].

$PV = CV + EV_f$

(b) If there is both firm and non-firm energy [Z<1.00]

$PV = CV + (EV_f \times Z) + EV_{nf} \times (1 - Z)$

Where

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will be stated in the annual data update notice in the Federal Register.

[37] Development of the appropriate fixed charge rate is discussed in *Hydroelectric Power Evaluation, supra* note 26.

[38] Note 22, *supra*.

[39] *Hydroelectric Power Evaluation, supra* note 28.

[40] *Id.* These include the fixed operation, maintenance, administrative, and general expenses.

[41] Note 23, *supra*.

[42] Note 34, *supra*. This factor varies with the size of the thermal alternative. For 600 MW coal-fired units, this factor is currently around 1.24.

[43] See *Hydroelectric Power Evaluation, supra* note 28; *see also* note 48, *infra*.

[44] This value will be based upon EIA data on average fuel costs in the region for year of project completion and on real fuel price escalation. These values will be specified in the annual Federal Register data update notice.

[45] This value will be based upon EIA data for recently constructed thermal generating units and will be specified in the annual Federal Register data update notice.

[46] This value will be based upon Table 4.4 of *Hydroelectric Power Evaluation, supra* note 26, as updated by U.S. Dep't of Labor wage rate statistics.

[47] *Hydroelectric Power Evaluation, supra* note 28, at 3-7.

Total power value (in cents per kWh)
b = Maximum expected annual generation of thermal alternative having equivalent capacity divided by the expected annual generation of the hydro project, expressed as

$$MAF \times ACFT \times PSCF$$

ACFT = Maximum expected annual capacity factor of thermal alternative.[78]

3. Power Value Formula Considerations

(a) *Control over Water Releases.* Federal dams are often constructed for non-power purposes, such as navigation, flood control or irrigation. Power development at these dams has certain unique characteristics. Ordinarily, the power project operator has no control over water releases at the dam. The water flows are scheduled without regard for electric demand levels. Hence, a project's output can reduce system capacity requirements only by the amount of effective project capacity available during the system-wide peak period.

Lack of control over water releases means that, in determining the capacity value formula as discussed above, the statistical availability of water flow during the peak load season must be used. However, hydrologic uncertainty is no different from the uncertainty of mechanical availability used in determining thermal capacity requirements. Consequently, the capacity value determination is consistent with the probabilistic evaluations used by utilities to establish capacity requirements.

(b) *Real "Inflation Free" Interest Rates.* The calculation of the power values and power costs is made in constant dollars, using the real, long-term, "inflation-free" cost of money.[79] The levelized annual net benefits, also in constant dollars based upon the inflation-free cost of money, thus express project net benefits in units of constant economic value. This permits a convenient adjustment to compensate for the shrinking value of the dollar due to inflation. Inflation results in a steady increase of current dollar project benefits but at unpredictable rates. Instead of attempting to estimate future inflation rates, the constant dollar charge will be indexed to the GNP deflator. Thus there is no need to use estimated interest rates in the power value formulas, which avoids the inevitable controversy on inflationary (or deflationary) economic trends.

This real "inflation-free" discount rate is applied to determined levelized annual capacity costs, corresponding to the investment and fixed costs of the alternative generation, and to the present-worthed, aggregate variable operating costs in determining levelized energy costs. The long-term, inflation-free cost of money is generally agreed to have been approximately 3 percent per year but there is some evidence of a recent increase. In 1979, the staff of the United States Nuclear Regulatory Commission selected at 3 percent discount rate for electric utility studies.[80] More recent evaluations indicate that the rate may be approaching 4 percent.[81] Consequently, the Commission proposes to use a 4 percent real "inflation-free" interest rate in annual charge determinations for privately-financed projects.

Examination of records on the average yields of tax exempt municipal bonds and corporate bonds show that, for a number of years, the tax exempt yields averaged about two-thirds of the equivalent grade corporate bond yields. However, in the past three years, tax exempt yields have increased to about three-fourths of the corporate yields. Consequently, the Commission proposes to use a 3 percent real "inflation-free" interest rate in determining the charges for projects with tax exempt financing.

By using the real, inflation-free cost of money, net benefits are stated in terms of constant dollars valued as of the year of project completion. The inflation adjustment factor, based upon the GNP Deflator, is then applied to determine the annual charge to be billed.

(c) *Capacity-Related Factors.* Because of continuing load growth and the need to construct new generation, the capacity value of a completed hydroelectric project will generally allow a utility to reschedule its construction program and achieve the cost savings represented by the capacity value. However, where a region has excess capacity and very low load growth, a utility in that region may not realize avoidable capacity cost until some year following initial operation of the hydropower project. The power value up to that year, therefore, is simply the savings in system energy costs.

In the computation of the total power value, an adjustment will be made in most cases to exclude capacity value for the first three years after the project becomes available for service,[82] unless the NERC regional reserve margin projection is less than 20 percent in any of these years. In that case, the capacity value component will be included for all years after the project is available for service. This assumption reflects the expectations that: (1) All regions will be planning continued capacity additions, even though small under low load growth conditions, (2) on the average, utility capacity expenditures cannot be reduced to reflect the hydropower addition until three years after project completion, and (3) that regions projection reserve margins of less than 20 percent within three years will still derive immediate benefit from the capacity added by a hydro project. The absence of capacity value for several years at the beginning of project operation will not have a major effect on the power value over the entire life of the hydro project. Nonetheless, this partial absence of capacity value is taken into account to avoid overestimating project net benefits.

(d) *Selection of Least Cost Thermal Alternative.* The least cost alternative to a project depends in part upon the mode of project operation, that is, whether it is run-of-the-river, peaking, subject to seasonal or environmental limitations, and so on. Customarily, a project's mode of operation can be approximately characterized by its average annual capacity factor, which is forecast from existing water flow records. An accurate power value calculation should represent the lowest cost alternative means of supplying capacity and energy equivalent to those of the hydro project. Usually, no single thermal alternative is exactly equivalent to the hydro project,

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[78] The appropriate maximum expected annual capacity factor for thermal alternatives will be specified in the annual Federal Register notice. These will be developed from EIA and NERC data.

[79] The nominal interest rate is linked with inflation in accord with the following expression:

$$(1+i) = (1+r)(1+e)$$

where

i = Nominal interest rate.
r = Real interest rate.
e = Inflation rate.

[80] U.S. Nuclear Regulatory Commission, *Treatment of Inflation in the Development of Discount Rates and Levelized Costs in NEPA Analyses for the Electric Utility Industry* (NUREG-0607, January 1980).

[81] *See, e.g.,* Spim, *The Real Rate of Interest for Corporate Planning in Public Utilities fortnightly* (Dec. 9, 1982).

[82] This adjustment will be made by determining the value of the power for the first three years of project operation as non-firm energy only. The aggregate present worth of the first three years net benefits will be added to the aggregate present worth of the benefits in the remaining years of the license term, which include a capacity value. Levelizing the total present worth over all the years of project operation results in the annual levelized net benefits.

although reasonable equivalent alternatives can be found.[53] Ordinarily, where control of water flow is possible, a simple cycle, combustion gas turbine provides the lowest alternative power cost for hydro projects with annual capacity factors of 5–10 percent; a coal-fired, cycling steam unit of simple design for capacity factors of 30–40 percent; and a high-efficiency, coal-fired baseload generating unit for capacity factors of 50 percent and above.

This selection of thermal alternatives is based upon situations where the hydro capacity is largely available during system peak periods. Where a substantial portion of hydro project capacity is not available at system peak periods, these approximations do not hold. This is generally the case for power projects added to existing dams. The effective capacity at peak load periods is only a portion of the installed capacity, so that the equivalent annual capacity factor of the thermal alternative is much higher than that of the hydro project. In these situations, high-efficiency coal-fired baseload units usually prove to be the least costly alternative, even for project annual capacity factors as low as 20 percent.

C. Project Cost Determination

The Commission proposes to use the actual legitimate original cost of the constructed project to determine the net benefits of a project. In determining this actual legitimate cost, the project developer will be required to use the costing standards and the accounts set forth in Account Nos. 330–335, 350–359, and 389–399.[54] Under the proposed rule, a project developer will be required to submit, within nine months after project completion, a statement from an independent certified public accountant (CPA)[55] verifying that the claimed construction cost conforms in all material respects to the requirements in the Uniform System of Accounts. The statement should include a listing of the amounts as recorded in each of the appropriate series of accounts. The project construction cost will be determined by the Commission based upon the cost shown in the developer's statement as certified by the CPA. Any exceptions noted by the independent CPA or any questions about the statement will be resolved initially by the Office of the Chief Accountant or, if necessary, by the Commission. If appropriate, the project construction cost can be adjusted from time to time if project works are added or retired. These adjustments could also result from a Commission compliance audit.

To complete the project power cost determination, O&M costs will have to be estimated. Licensees will be given an opportunity to submit their own O&M cost estimates, and the Commission will use these licensee estimates unless they depart significantly from reasonable forecasts based upon standard industry data. In such case, the Commission will determine the most reasonable O&M cost estimates to use. To arrive at the O&M estimates, the Commission currently intends to use the historical data of Table 4.6 of *Hydroelectric Power Evaluation,*[56] indexed to current costs by the Department of Labor's statistics on hourly earnings of electric company workers.[57]

D. Determining Annual Net Benefit

Once the power value for a given project is found and once the project power costs are determined, the net benefits can be calculated. The following formula will be used.[58]

$$ANB = IC \times ACF \times 8760 \times (PV - PC) \times 10^{-5}$$

where

ANB = Annual net benefit (in dollars)
IC = Installed capacity of the project (in kW)
ACF = Annual capacity factor
8760 = Hours in a year
PV = Power value (a determined from earlier formula and expressed in cents per kWh)
PC = Project power cost (as determined from estimated O&M and actual construction costs and expressed in cents per kWh)
10^{-5} = Conversion factor

As discussed earlier, the annual charge will equal 50% of the annual net benefit (ANB), set in constant dollars as of the year project constuction is completed, and adjusted yearly for inflation.

IV. Illustrative Examples of Net Benefits Determination

The Commission is providing illustrative examples of the net benefits calculation process to better demonstrate how the proposed formulas work and how the sample tabulation of selected power values will appear in the annual Federal Register data update notice. In this Section, the individual steps for determining power values, project power costs, and net benefits are presented and explained.

A. Power Value Data

Data of the type to be presented in the annual update have been developed using the power value methodology described above. The data are based on tax-exempt financing and show both the assumptions employed and the resulting power values for two regions, New England and Wyoming, which are expected to be representative of the highest and lowest power values respectively. The data illustrate the power values that would apply to projects completed in 1982 with 45 years remaining in the term of the license. The data are for illustrative purposes only and do not represent official determinations.

1. Least Cost Alternative Data.

	New England	Wyoming
Alternative thermal capacity	Baseload coal	Baseload Coal
Unit size (two unit plant)	600 MW	600 MW
On-line date	July 1982	July 1982
Start construction first unit	July 1975	July 1975
Operating lifetime	35 years	35 years
Average interest rate during construction, percent	7.5	7.5
Investment cost (I), $/kW	895	868
Fuel	Bituminous	Bituminous
Heat Rate (HR), Btu/kWh	10,100	10,100

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[53] In normal utility operations, a combination of generating units is used to supply each increment of load in the most economical fashion. Thus, the cost of each increment of power is determined by a blending of the costs of discrete units used to provide that power increment. The power value formulas and calculations assume the ideal generating unit combination in determining the power value at each capacity factor.

The actual incremental cost is slightly higher than the cost of an ideal generating system having continuously variable design parameters, optimized for the capacity factor of each load increment. The difference, however, is normally less than the uncertainty in cost estimations.

[54] See 18 CFR 4.1; Uniform System of Accounts, 18 CFR Part 101, including general instructions, electric plant instructions, and the instructions for Accounts 330–335, 350–359, and 389–399. For projects with installed capacity over 10,000 kW, costs under Accounts 330–335 are reported by jurisdictional utilities in FPC Form 1.

[55] See 18 CFR 41.12 (defining who may qualify as an independent certified public accountant).

[56] *Supra* note 26.

[57] These statistics are published annually in United States Department of Labor, Supplement to Employment and Earnings.

[58] The net benefit is stated as cents per kilowatt of annual production. When multiplied by the annual production (installed capacity x annual capacity factor x hours in the year) and divided by 100 to convert cents to dollars, the result is the annual project net benefit in dollars.

	New England	Wyoming
Maximum expected annual capacity factor thermal (ACFT)	0.6	0.6
Fuel cost (1982), ¢/million Btu	233.0	77.4
Escalation of real fuel cost, percent per year (EIA)		
July 1982 to July 1985	13.93	13.87
July 1985 to July 1990	−2.78	0
July 1990 to July 1995	0.66	0.34
Fuel cost multiplier	1.31	1.47
Levelized cost of fuel (F), ¢/million Btu	305.2	113.8
Cost of money (zero inflation), percent	3.00	3.00
Depreciation (3%, 35-year sinking fund), percent	1.654	1.654
Annual tax rate, percent of investment	0	0
Annual insurance cost, percent of investment	0.25	0.25
Fixed charge rate (zero inflation) (R), percent	4.904	4.904
Average fuel inventory, percent of annual consumption	30	25
Annual levelized fuel inventory cost (FIC), $/kW	0.87	0.45
Annual levelized fixed O&M cost, $/kW	15.92	15.82
Annual levelized administrative and general expenses, $/kW	5.26	5.25
Annual total fixed operating cost (FOC), $/kW	21.18	21.16
Annual levelized variable O&M cost (O&M), ¢/kWh	0.24	0.24
Capacity cost of alternative, (I × R + FIC + FOC), $/kW-yr	66.04	64.70
Energy cost of alternative, (F × HR × 10^{-6}) + O&M, ¢/kWh	3.32	1.39
Mechanical Availability Factor (MAF)	1.20	1.20

2. Average Marginal Energy Costs of Regional Electric Systems ("System Lambda").

1982 dollars	New England	Wyoming
For 1982, ¢/kWh	5.65	0.87
For 1990, ¢/kWh	5.56	1.45
For 2020, ¢/kWh	3.78	1.48
Levelized cost (1982-2027), ¢/kWh	4.85	1.42

3. Discussion of Least Cost Alternative Data

(a) *Selection.* A series of calculations has shown that for hydropower projects having annual capacity factors in the range of 0.3 to 0.6, and peak season capacity factors not exceeding 0.5, the least cost alternative is generally a baseload coal-fired plant. These ranges of capacity factors are used in the illustrations and are expected to reflect most hydropower projects constructed at Federal dams. To determine the appropriate size of the alternatives, it was noted that coal-fired units up to 550 MW were being constructed in the Wyoming area in the early 1980's and a unit of approximately 570 MW is planned for service in New England in the late 1980's. Consequently, a 500 MW unit size was selected as appropriate for these areas. Since the lowest investment cost per kilowatt generally results from construction of large generating units in pairs, a two-unit plant is postulated. In both areas the fuel is bituminous coal and full environmental control of stack emissions and cooling water is assumed.

(b) *Investment Cost.* The investment costs of two-unit plants completed in mid-1982, assuming construction of the first unit began in mid-1975, are calculated using the CONCEPT 5 cost estimating code. The weighted average interest rate on funds used during construction is assumed to be 7.5 percent, based on the historical record of municipal bond rates published in the quarterly U.S. Department of the Treasury, *Treasury Bulletin.* The code automatically schedules construction expenditures and includes the total interest during construction in the aggregate construction cost. The differences in costs between the New England and Wyoming areas chiefly reflect differences in local labor rates and productivity.

(c) *Heat Rates.* The heat rates of steam electric units depend upon the steam temperature and pressures, the extent of reheat and regenerative provisions, the environmental equipment required, and the fuel characteristics, among other factors. Over the past 15 years, data compiled by the Energy Information Administration [59] show that the average operating heat rate for fossil-fueled steam electric plants has remained virtually constant, in the range of 10,350 to 10,400 Btu per kWh, despite large additions of new plants to the inventory. One factor has been the parasitic load of environmental equipment, which has consumed efficiency gains made in other areas.

Various studies [60] indicate that the design choices likely to be made by utilities would result in coal-fired steam plant heat rates at full load in the range of 9600 to 10,000 Btu per kWh. The heat rates with bituminous coal average about 200 Btu/kWh lower than with sub-bituminous coal. Average lifetime heat rates appear to be 3–4 percent more than the full-load heat rates of units.

On the basis of these considerations, the average lifetime heat rate used for new coal-fired units completed in 1982 is 10,100 Btu/kWh for bituminous coal and 10,300 Btu/kWh for sub-bituminous coal.

(d) *Fuel Cost.* The cost of coal delivered to a power plant reflects extraction costs, which vary widely, and transportation costs, which depend on distance and mode. Since utilities try to locate generating plants to minimize total power costs (including transmission costs), large differences in delivered coal prices within an area tend to represent either (a) the existence of limited supplies of low cost coal which can serve only one or, at most, a few plants, or (b) non-optimum plant siting resulting from factors such as unavailability of cooling water, environmental requirements, or the inability to construct transmission lines. New generating plants will generally not be able to acquire coal at the lowest cost reported by existing plants, but also will not necessarily have to incur the highest coal costs. Since detailed siting analyses are not practicable, the average fuel costs of regions selected for general similarity of coal sources and costs are used as a measure of the coal cost for a new plant located in the area.

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[59] Energy Information Administration, *Thermal Electric Plant Construction Cost and Annual Production Expenses.*

[60] Electric Power Research Institute, *Coal-Fired Power Plant Capital Cost Estimates* (May 1981).

Energy Information Administration data on delivered coal costs for all of 1982 are not now available. Consequently, 12 month average cost data through October 1982, published by EIA in its monthly report,[61] are used.

(e) *Fuel Cost Escalation.* Real coal price escalation (price increases in excess of the general rate of inflation) are inevitable, in view of the progressive exhaustion of the more easily worked mineral deposits. However, the rate of escalation is influenced by technology development and the stimulus of competition with other energy sources. Forecasts of real future coal price escalation are therefore subject to much uncertainty. From 1973 through 1982, the real fuel price escalation of coal averaged 8.5 percent per year. The most recent (1981) forecast of the Energy Information Administration [62] projected the national average real price of coal to escalate at a rate of 3.4 percent per year from 1983 to 1995. The EIA regional estimates of escalation for specific periods are used in the illustrative development of power values.

Because of the uncertainty as to the escalation of coal prices over the full term of a license and the sensitivity of the net benefit estimate to the escalation assumption, the period of assumed real fuel price escalation is presently limited to the first 10 years of project operation. The fuel escalation multipliers, shown above, convert the assumed fuel prices in each year of project operation to a levelized price, including the assumed escalation. The levelizing term is for the period from the time the project becomes available for service until the end of the licensed term. This period is taken to be 45 years in the illustrations.

(f) *System Lambda (Average Marginal Energy Cost).* Currently, larger utilities are required biannually to file with the Commission cost of service data [63] which include actual and projected monthly marginal energy costs.

However, the data for alternate years are not included and are not available in other published reports. Consequently, although the utility filings appear to offer a means of determining individual system average marginal energy costs, the data may not be sufficiently timely, complete, or certain for the purposes of this rulemaking. As an alternative, the average marginal energy cost on a utility system may be empirically approximated for most systems, in cents per kWh, as 1.25 times the average fuel cost, in dollars per million Btu, of fuel used for the upper 25 percent of the system's energy requirements, applying the most costly fuels used by the system up to the amounts of each fuel actually consumed.

Areas selected for regional power value determinations will have a considerable degree of interconnection and coordination among the utilities, sometimes through formal pooling arrangements. Consequently, there will be exchanges of economy energy tending to reduce the disparities among marginal costs of individual systems. Therefore, the weighted average marginal energy cost in a region is used to establish the estimated regional power values. If the empirical fuel price estimating method is used, the regional fuel prices and amounts may be used directly to obtain the estimated regional average marginal energy cost. This method has been used for the purpose of the illustrations.

In New England, oil is the highest cost fuel and constituted 75 percent of the fuel Btu delivered in the 12 month period through October 1982. Oil supplies approximately 50 percent of total New England generation. Consequently, the cost of oil is used to estimate the marginal energy cost in that region. In Wyoming, coal is essentially 100 percent of the fuel used for electric generation, and its price governs the marginal energy cost. In other regions, where the highest cost fuel may not be used for more than 25 percent of the energy produced, a weighted combination of the highest cost fuels must be used to estimate the marginal energy cost.

(g) *Mechanical Availability Factor.* The factor is calculated from a North American Electric Reliability Council report prepared in connection with its Generating Availability Data System (GADS). The report used for the illustrations is *Ten Year Review, 1971–1980, Report on Equipment Availability.* Outage statistics are presented for fossil fuel generating units grouped by sizes.

The EFOR for fossil units of 400 to 599 MW is 16.44 percent. For units of 600 to 799 MW, it is 20.55 percent. The average, 18.50 percent, is taken to be representative of utility expectations for 600 MW coal-fired units completed in 1982. The hydropower unit statistics are not grouped by sizes. The ten year data show an EFOR for hydro units of 1.85 percent.

Consequently, the Mechanical Availability Factor is calculated as:

$$\mathrm{MAF} = \frac{1-\mathrm{EFOR}_h}{1-\mathrm{EFOR}_t} = \frac{.9815}{.8150} = 1.20$$

4. Illustrative Power Value Calculation.

New England Area

Project annual capacity factor = .45
Project peak season capacity factor = .35

(a) *Capacity value component:*

$$\mathrm{CV} = [(I \times R) + \mathrm{FIC} + \mathrm{FOC}] \left(\frac{100}{8760}\right) \left(\frac{\mathrm{PSCF}}{\mathrm{ACF}}\right) (\mathrm{MAF})$$

$$= (\text{Alternative Capacity Cost}) \left(\frac{100}{8760}\right) \left(\frac{\mathrm{PSCF}}{\mathrm{ACF}}\right) (\mathrm{MAF})$$

$$= (66.04) \left(\frac{100}{8760}\right) \left(\frac{.35}{.45}\right) (1.20)$$

= 0.704 cents per kilowatt-hour of total project annual generation [64]

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[61] Energy Information Administration. *Cost and Quality of Fuels for Electric Utility Plants.*

[62] Energy Information Administration. *Annual Report to the Congress.*

[63] 18 CFR Part 290.

[64] The adjustment for absence of capacity value in the first three years of operation is not made in the illustrative data because of the involved nature of that calculation. A computer program will be used to carry out the process described in footnote 52, *supra.*

(b) *Firm energy value component:*

$EV_f = (F \times HR \times 10^{-6} + O\&M) + EV^a$
= Alternative Energy Cost + 0
= 3.32 cents per kilowatt-hour of firm energy generation

The energy value adjustment is not applicable since the thermal alternative will not supply as much energy as the project. In this case the firm energy of the project, by definition, is the same as the energy of the alternative, so that no adjustment is needed.

$$Z = \frac{\text{Annual generation of alternative}}{\text{Annual generation of project}} = MAF \times ACFT \times PSCF$$

$$= \frac{(1.20)\,(.60)\,(.35)}{.45} = .56 \text{ (Less than 1.0, no adjustment)}$$

When Z 1.0, there is no non-firm energy supplied by the project and the difference in generation between the project and the alternative must be accounted for. The energy value adjustment is:

$EV_a = (A-1)\,(EC_1 - EC_s)$
Where EC_1 = Energy cost of alternative, ¢/kWh
EC_s = Marginal system energy cost (System lambda), ¢/kWh

(c) *Non-firm energy value component:* Non-firm energy is that supplied by the project in excess of that which would be supplied by the thermal alternative of equivalent capacity. It is valued at the average marginal energy cost, or system lambda, of the electric systems in the region.

As determined from regional fuel use and fuel cost as described in the assumptions for the illustrative data, the levelized non-firm energy value is:

EV_{nf} = 4.65 cents per kilowatt-hour of non-firm generation

(d) *Total power value.*

$PV = CV + (EV_f \times Z) + EV_{nf} \times (1-Z)$
$= .70 + (3.32)\,(.56) + (4.65)\,(.44)$
$= 4.81$ ¢/kWh

5. Sample Power Values for New England.

- Total power value in cents per kilowatt-hour of project annual generation, levelized 1982–2027, in 1982 dollars.
- Coal-fired baseload alternative, tax-exempt financing.
- All non-firm energy valued at levelized system lambda, 4.65 cents/kWh.

Annual capacity factor of project	Peak season capacity factor of project	Value of capacity	Value of firm energy	Ratio firm to total energy	Power value
.30	.30	.80	3.32	.66	4.81
	.35	1.06	3.32	.84	4.58
	.50	1.31	3.06	1.00	4.56
	.65	1.96	2.57	1.00	4.53
.45	.20	.40	3.32	.32	4.63
	.35	.70	3.32	.56	4.81
	.50	1.00	3.32	.80	4.59
	.65	1.31	3.27	1.00	4.56
.60	.20	.30	3.32	.24	4.83
	.35	.58	3.32	.42	4.62
	.50	.75	3.32	.60	4.81
	.65	.90	3.32	.78	4.58

6. Sample Power Values for Wyoming.

- Total power values in cents per kilowatt-hour of project annual generation, levelized 1982–2027, in 1982 dollars.
- Coal-fired baseload alternative, tax exempt financing.
- All non-firm energy valued at levelized system lambda, 1.42 cents/kWh.

Annual capacity factor of project	Peak season capacity factor of project	Value of capacity	Value of firm energy	Ratio, firm to total energy	Power value
.30	.25	.58	1.26	.48	1.89
	.35	1.02	1.26	.84	2.48
	.50	1.47	1.26	1.00	2.94
	.65	1.90	1.26	1.00	3.36
.45	.25	.39	1.26	.32	1.80
	.35	.68	1.26	.56	2.08
	.50	.98	1.26	.80	2.37
	.65	1.27	1.26	1.00	2.66
.60	.25	.29	1.26	.24	1.71
	.35	.51	1.26	.42	1.92
	.50	.73	1.26	.60	2.14
	.65	.96	1.26	.78	2.35

B. Project Power Costs

To illustrate the calculation of project power costs and the sensitivity of net benefits to project characteristics (in Section IV.C), two projects are postulated. One is a small size, low-head project. As with the thermal alternative power cost determinations, a 3 percent real cost of money is used for the levelizing process in the illustrations.

The project power costs are developed in the illustration as entirely fixed costs, expressed as dollars per kilowatt-year. This is a common convention to estimate net benefits. However, if the licensee submits data which separate the operating and maintenance costs into fixed and variable components, the project power costs will be developed with both components.

The illustrative data for the two assumed projects are as follows:

	Low head low capacity project	High-head, medium capacity project
Effective head, feet	20	200
Installed capacity, MW	5	50
Investment cost (1982$), $/kW *	2,200	500
Cost of money (zero inflation), percent	3.00	3.00
Depreciation (3%, 45 year sinking fund), percent	1.079	1.079
Annual tax rate, percent of investment	0	0
Annual insurance cost, percent of investment	0.10	0.10
Fixed charge rate (zero inflation)(R), percent	4.089	4.089
Annual levelized fixed O&M cost $/kW	12.58	14.37
Annual levelized administrative and general expense, $/kW	4.40	5.02
Annual total fixed operating cost (FCC), $/kW	16.98	19.39
Annual levelized variable O&M cost, ¢/kWh	0	0
Annual capacity cost of project (I × R + FCC), $/kW-yr	106.94	39.84
Annual energy cost of project, ¢/kWh	0	0

* Approximate costs are derived from Figure 7.1 of *Hydroelectric Power Evaluation*, supra note 28, and Figures 2-3 and 2-4 of the Electric Power Research Institute report *Simplified Methodology for Economic Screening of Potential Low-Head Small Capacity Hydroelectric Sites* (January 1981). Costs are adjusted to July 1982 levels and include interest during construction and an allowance for land, access roads, transmission, etc. Actual costs for different projects with the same capacity and head can vary by as much as 50 percent.

The project power cost, per kilowatt-hour, is simply the annual project cost divided by the annual kilowatt-hours produced. Hence,

$$\text{Power cost} = \frac{\$/\text{kW-yr.}}{(8760 \text{ hrs. in year})(\text{project annual capacity factor})}$$

C. Net Benefits Calculation

As described above, the project annual net benefit is the saving in cost per kilowatt-hour of annual production from the project, as compared to the cost per kilowatt-hour from the least costly economic alternative, multiplied by the number of kilowatt-hours produced annually. The following illustrates the net benefit determination.

Region: New England

Project: Installed capacity: 5 MW

Head: 20 feet

Investment cost: $2,200/kW

Annual levelized capacity cost: 106.94 $/kW-yr.

Annual capacity factor: 0.45

Peak season capacity factory: 0.35

Power Production

$$\frac{(106.94/\text{kW-yr.})(100 \text{ cents in dollars})}{\text{Cost} = (8760 \text{ hrs. in year})(0.45 \text{ annual capacity factor})}$$

= 2.71 cents per kilowatt-hour of annual generation

Net benefit/kW-hr. = (Power value—Power cost)

= 4.81 − 2.71 = 1.90 cents-kWh

Annual net benefit: = (NB/kWh) (Capacity in kW) (ACF) (8760) (10^{-2})

= $374,490/year

The following tables show, for illustrative purposes only, the net benefits that would result from the two assumed projects in New England and Wyoming, at various annual and peak season capacity factors. The sensitivity of the net benefit to the project cost and the capacity factor is shown. The smaller, high-cost per kilowatt project appears to be uneconomic in the lower power value region, except if maximum annual and peak season capacity factors are achievable.

1. *Sample Annual Net Benefits in New England* (1982 Dollars).

Project capacity megawatt	Head feet	Annual capacity factor	Peak season capacity factor	Power cost ¹	Net benefit ¹	Annual net benefit (dollars)
5	20	.30	.25 .65	4.08	.53 .47	69,642 61,758

Project capacity megawatt	Head feet	Annual capacity factor	Peak season capacity factor	Power cost¹	Net benefit¹	Annual net benefit (dollars)
		.45	.35 .65	2.71	1.90 1.87	374,490 368,577
		.60	.35 .65	2.03	2.59 2.56	680,652 672,768
50		.30	.35 .65	1.82	3.07 3.01	4,033,980 3,955,140
		.45	.35 .65	1.21	3.60 3.57	7,095,600 7,036,470
		.60	.35 .65	.91	3.85 3.83	10,117,800 10,065,240

¹Cents per kilowatt-hour.

2. *Sample Annual Net Benefits in Wyoming* (1982 Dollars).

Project capacity megawatt	Head feet	Annual capacity factor	Peak season capacity factor	Power cost¹	Net benefit¹	Annual net benefit (dollars)
5	20	.30	.35 .65	4.06	−1.64 −.89	−215,496 −117,130
		.45	.35 .65	2.71	−.62 −.05	−122,202 −9,855
		.60	.35 .65	2.03	−.11 +.32	−28,908 +84,096
50	200	.30	.35 .65	1.82	.90 1.74	1,182,600 2,286,360
		.45	.35 .65	1.21	.88 1.65	2,179,600 3,252,150
		.60	.35 .65	.91	1.16 1.59	3,048,480 4,178,520

¹Cents per kilowatt-hour.

V. Application of Proposed Rule

A. Nominal Annual Charge

As determined from the estimated power value and project power cost, the estimated net benefits of a project will be a general indicator of the long-term, economic value of the project. It is possible, however, for this estimated net benefit to be zero or negative, as in some of the illustrative calculations. In such a case, if a developer otherwise can demonstrate during the licensing period that the project is economically and financially feasible,[56] the Commission proposes to charge a nominal fee of one hundred dollars per year. This amount will cover the cost of rendering the annual bill. The Commission is not, under section 10(e) of the Act, permitted to allow a zero annual charge in any year of the project license term. Therefore, the Commission will also charge the same nominal charge of one hundred dollars per year for all years preceding the year in which the project becomes available for service (*i.e.*, when construction is complete).

B. Option To Defer Annual Charges Payment

As indicated above, the bill for each year before the project is available for service (when construction is complete) will be the nominal charge of one hundred dollars. Following the time when the project is available for service, the billed annual charges will be based upon the generic methodology described in the Notice.

For certain hydroelectric projects, however, operations in the first few years may not yield positive net revenues, particularly if the project was initially financed in an inflationary period at a high interest rate. For projects to be economical, this situation must, and normally does, reverse itself in later years with increased revenues and diminished costs. Certain developers may, therefore, have difficulty in meeting the annual charge payment when billed in the first few years of project operation unless their financing arrangements include provision for the payment of annual charges. In order to provide flexibility, the Commission is proposing to allow project developers the option to defer some annual charge payments under certain circumstances. This deferral option would be available to developers only for the first ten years following the issuance of the project license. Deferral of annual charges billed before the project is constructed and available for service (*i.e.* the nominal one hundred dollar charge) will not be permitted. Thus, the number of billed payments that can be deferred depends on the time it takes to complete project construction. Any deferred payments would accrue interest during the period of deferral.[47]

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[56] For example, a developer might be able to show that the market price for that particular project's power will exceed the estimated regional power value.

Developers may elect this payment deferral option if a statement from an independent certified public accountant verifies that project revenues for that year are less than the billed annual charge amount. Of course, developers may continue to make financing arrangements that will permit annual charge payments to be made as billed regardless of yearly net revenues. Under no circumstances, however, will the deferral option be available to a developer in any year if the project revenues for that year of operation are sufficient to meet the annual charge payment as billed.

C. Projects Subject to Rule

The Commission proposes to apply this net benefit methodology to four categories of projects using Government dams or other structures. This first three categories are: (1) Projects for which licenses are issued after the effective date of this rule, (2) projects that are being relicensed, and (3) projects whose annual charges are being readjusted.

The fourth category covers those projects whose licenses, because of the pendency of this rulemaking, do not specify an exact annual charge amount to be billed. For currently licensed projects, these licenses generally either (a) prescribe a maximum amount, which the annual charge established by the rulemaking cannot exceed; or (b) state that the annual charge will be that determined by this rulemaking. The final rule in this docket will also be applied to these types of projects and licensees.

Other projects, completed before the effective date of this rule and for which specified annual charges are now being collected, will not be subject to this rule.

In addition, pumped storage projects using Government dams or other structures would not be subject to the proposed general methodology for determining annual charges. In practice, it is considerably more difficult to establish a reasonably accurate estimate of power value for a pumped storage project than for a conventional project. The power value depends critically upon the using utility's hourly load curve, which changes with the season of the year and with the generation mix of the specific utility. A generalized estimate of power value would require numerous assumptions that would not fit many projects. The resulting net benefits determination is, therefore, likely not to have acceptable accuracy.

Because of these problems, this rule will not cover annual charges for pumped storage projects using Federal dams. There are only 18 Commission licenses that have been issued for pumped storage projects, and only one is for a project at Government dam. Since pumped storage projects at Federal dams will account for such a small proportion of the total number of projects subject to section 10(e) annual charges, the Commission will determine the annual charges for these projects on a case-by-case basis.

D. Submission of Actual Cost Data

Under the proposed rule, each project developer must submit a statement from an independent certified public accountant that verifies the actual legitimate cost of constructing the project. This statement is to be filed with the Commission within nine months after project construction is completed. In addition, this statement must certify that the claimed construction cost conforms in all material respects to the accounting requirements of Account Nos. 330–335, 350–359, and 389–399 in the Uniform System of Accounts, 18 CFR Part 101. Where there are variances, they will be resolved by the Commission. The rectified cost figures will be used in the calculation of project net benefits and annual charges.

Because the requirement for a statement verifying the actual project cost under this proposed rule differs slightly from the current reporting burden, there may be a new reporting burden under the Paperwork Reduction Act of 1980, 44 U.S.C. §§ 3501 *et seq.* The Commission intends to obtain any necessary clearances from the Office of Management and Budget pursuant to normal procedures.

E. Readjustments and Relicensing

As provided under section 10(e) of the FPA, an annual charge can be readjusted at specific points beginning with 20 years after a project is available for service. The indexing of annual charges to the GNP Deflator should make it less likely that readjustments will be necessary. However, some uncertainties, such as estimating long-term real fuel cost escalation, may lead to the need for readjustments. Nothing in this rule is intended to affect the right to request or to conduct a readjustment pursuant to section 10(e). The Commission proposes to apply the generic methodology discussed in this Notice for any readjustment, subject to statutory notice and opportunity for hearing on the need for a readjustment.

Once a project license expires, section 15 of the FPA provides for relicensing of the project. At that time, the Commission is entitled to impose a new annual charge on the holder of the new license. This rulemaking also applies to determination of annual charges in these relicensing situations. Since this rulemaking proposes to adopt standard techniques for determining net benefits of a project, this rule is equally suitable for relicensed projects. The determination of net benefits in relicensing situations will be based upon that period of time covered by the new license.

F. Inflation Adjustment or Indexing

As described above, the net benefits determintion will yield a number representing the total annual net benefits conferred upon a licensee. This number will be expressed as an amount in dollars of the year in which the project is completed. Fifty percent of that constant dollar amount represents the yearly annual charge that will be billed to the licensee. The Commission proposes to maintain the real worth of the annual charges by adjusting that amount according to the GNP Deflator. Thus, while the actual billed amount will vary each year depending on inflation, the economic value of the payment will remain the same.

In situations such as this, where the benefit of a project is to be expressed in monetary units, the fact of inflation is critical to the calculation. For correct determinations, the net benefit of a project should be expressed in terms of constant economic units. To achieve the objective of normalizing the annual costs and benefits in each future year to a constant economic unit (here a constant dollar measure), present worthing of the costs and benefits to the starting year is employed. This technique factors out inflation as long as the assumed inflation rate determining the level of costs in future years and the assumed nominal interest (discount) rate are properly related. After the nnual "inflation-free" net benefits mount is determined, dollar shrinkage s taken into account by the inflation djustment per the GNP Deflator.[68] In ddition to making annual payments qual in economic value, this indexing cheme should allow annual charge payments to be better matched to actual project revenues (which also increase with inflation).

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[47] No interest would be collected on any annual charge payments until the deferral had actually begun, that is, after the billing of the annual charge for the year in which the project becomes available for service. The interest rate applied will be that specified in 18 CFR 35.19a(a)(2)(iii). The Commission may, in its discretion, grant a licensee's request to defer payments over successive years, starting with the eleventh year. For example, deferred payments for years 5, 6, and 7 could be due in years 11, 12, and 13.

The current case-by-case SNB method of levelizing costs and benefits, using estimated interest rates, includes a built-in projection of inflation. If this method were used to set the annual charges for use of a Federal dam, the aggregate payments over the life of the project give the Government its fair share of the net benefit only if the actual inflation rate matches the assumed rate. Further, this method of levelized current dollar accounts requires payments in the early years representing a greater economic value than those made in later years, with a correspondingly greater economic burden on the licensee in the early years.

Thus, for reasons of accuracy and equity, the Commission is proposing to determine project net benefits using the real inflation-free cost of money. Based on a review of available data and rates adopted by other agencies, the Commission believes the real, long-term, inflation-free interest rates to be approximately 3% to 4% for private financing and 2% to 3% for public financing. Because lower interest rates often, but not always, tend to increase the estimated net benefits, the Commission proposes to apply a rate of 4% for private financing and 3% for public financing. These rates will allow for reasonable, but conservative, estimates of net benefits and determinations of annual charges.

G. Annual Update of Power Value Data and Inflation Adjustment Factor

The Commission proposes to issue an annual update of the basic data used to determine regional power values and of the tables showing sample power values for selected project capacity factors. The data will establish the regional power value data applicable to all projects completed or relicensed in that year and to all projects undergoing readjustment of annual charges under section 10(e) procedures. Except for relicensing and readjustment situations, the update would not affect the power values or net benefit determinations for projects completed in other years. The updating will serve primarily to keep the power value calculations up to date. The update will use the annual fuel cost data from EIA's *Cost and Quality of Fuels for Electric Utility Plants*, revised thermal alternative investment costs from the Concept-5 code,[69] updated Department of Labor data on electric utility costs,[70] and NERC data on projected regional peak loads and reserve margins.[71]

The annual updating will also include the inflation adjustment factor that will be applied to all annual charges billed during that year. As discussed earlier, this adjustment factor will be equal to the level of inflation or deflation for the past year, based upon the GNP Deflator. The Commission believes this inflation index to be appropriate, but invites comment on whether another inflation index would be more suitable than the GNP Deflator.

The annual update is expected to be published in the Federal Register in the first half of a given calendar year, depending on how quickly the previous year's data becomes available. Once the updating is fininshed, the yearly billing for annual charges will be sent to project licensees.

H. Licensee Contributions to Dam Construction and Approval of Secretary of Interior

This rulemaking implements section 10(e) of the Federal Power Act by setting a reasonable annual charge based upon the net benefits of the hydroproject. Section 10(e) makes it clear that the Commission is responsible for fixing the charge; that responsibility is being discharged in rulemaking. The Commission, to meet section 10(e) and to fulfill its unilateral licensing authority under section 4(e), must be in a position to ensure that the Government receives its fair share of Federal benefits conferred on non-Federal licensees. Commission licensees at dams owned by the United States Bureau of Reclamation (BuRec) sometimes make arrangements to pay for some or all the cost of dam construction. The Commission is of the opinion that it is inappropriate to allow a credit for these payments to BuRec against the billed annual charges under section 10(e) of the FPA. The BuRec payments are normally designed to repay the costs of construction of the dam or for benefits not related to power produced at the dam. As a result, these payments to BuRec would not qualify in nature as section 10(e) payments, which are intended to value economic benefits conferred by the Government by looking to the least costly alternative source of power and the project powerhouse costs (not dam construction costs).[72]

As mentioned earlier, one clause of section 10(e) states that annual charges fixed by the Commission for reclamation projects are "subject to the approval of the Secretary of the Interior." Conversely, section 10(e) also states without qualification that "but in no case shall a license be issued free of charge for the development of power created by a Government dam and that *the amount charged therefor in any license shall be such as determined by the Commission*" (emphasis added).[73] The Commission believes that, in light of its responsibilities under section 4(e) and the language in section 10(e), the Commission itself is responsible for determining the annual charges to be paid by licensees. This is consistent with the court's opinion in *Montana Power Co. v. FPC.*[74] As mentioned in *Montana Power*, the Secretary has the right to intervene into those licensing proceedings and to recommend an annual charge. If the Secretary of the Interior does not agree with the amount fixed by the Commission, he may register his disagreement with the Commission on rehearing of the licensing order. If the Secretary continues to maintain that the Commission's determination of the annual charge is unreasonable, the Secretary may appeal that determination to the courts.

To interpret section 10(e) differently would grant the Secretary a unilateral veto power over Commission annual charges. This result would be significantly at variance with the language of section 10(e), the court's specific language in *Montana Power*, and the scheme of statutory powers over hydroelectric power licensing committed to the jurisdiction of this Commission.

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[68] For maximum precision, the inflation index applied should exclude real fuel price escalation since a forecast of such escalation was used in determining the net benefit estimate. However, the resultant difference in the inflation index is likely to be so small as to be not significant.

[69] Note 21, *supra*.

[70] These data are published annually by the United States Department of Labor in its *Supplement to Employment and Earnings*.

[71] These data are found in the annual publication of the North American Electric Reliability Council, *Electric Power Supply and Demand*.

[72] *See, e.g.*, Solano Irrig. Dist., 19 FERC ¶ 61,228 (May 25, 1982); 14 FERC ¶ 61,040 (Jan. 22, 1981). The Commission's determination of annual charges under section 10(e) is independent of any determination made by the BuRec under section 9(c) of the Reclamation Act of 1939, 43 U.S.C. 485h(c)(1976). East Colum. Basin Irrig. Dist., 21 FERC ¶ 61,091 (Nov. 22, 1982).

[73] This unilateral power to set annual charges is also echoed by the initial clause of section 10(e), which states "the licensee shall pay to the United States reasonable annual charges in an amount fixed by the Commission * * * for recompensing it for the use, occupancy, and enjoyment of its lands or other property * * *."

[74] 459 F.2d 863 (D.C. Cir. 1972). This case involves annual charges for a project on tribal lands. However, the "approval clause" is equally applicable to projects at Government dams and to projects on Indian lands.

VI. Other Alternatives Considered

Several alternatives have been considered. These include: (1) A flat rate charge for project energy produced; (2) a flat charge per project; (3) case-by-case sharing of the benefits based on actual revenues (royalty method); and (4) codification of the current case-by-case, sharing of the net benefits (SNB) method.

The Commission has concluded, first, that a generic net benefits method is most appropriate. A generic method will save the Commission and licensees considerable expenditure of time and resources. The unpredictability and variations inherent in case-by-case estimates of net benefits are also avoided. By reducing this unpredictability, a generic method will help to meet the needs of applicants, lending and grant agencies, financial institutions, and others who must predict annual charges as a part of their planning and financial decisions on the economics of a project.

A. Flat Rate Charge for Project Energy Produced

Under this method, a licensee would be charged a flat rate—in cents per kilowatt hour—for each kilowatt hour of energy produced at the project. Either regional or national rates could be created. The regional or national rate would be based on the average net benefit per kilowatt hour for the previous year, estimated from recorded regional or national costs of energy from thermal generation[73] and recorded regional or national costs of hydro projects at Government dams.[74] The Commission could set the rate at some percentage of the average estimated net benefits per kilowatt hour.

This method would appear, at first glance, to be relatively simple to calculate and to apply. Annual cost data, not now required from licensees, would have to be obtained, but some of the necessary data are published regularly. Redetermination of the kilowatt hour change each year would provide an adjustment for inflation with relatively little burden on the Commission staff. The charge would also be fairly predictable since a developer could estimate an annual charge by simply multiplying the most current published rate by the expected annual project output.

There are, however, significant disdvantages to this approach. First, this method would not recognize the enormous variations between projects and project net benefits. Any kilowatt hour charge method would discourage development of the projects having marginal net benefits, unless the charge is set so low as to return to the Government only a small portion of the actual net benefits.

Second, since the flat rate method does not assess charges proportional to the value of the benefits received by an individual licensee, this approach may not comport with section 10(e), at least as interpreted by *Vanceburg*. In addition, this method uses alternative energy costs as the only measure of power value. This allows for no capacity benefits, an assumption that may not be valid for all projects. Finally, there are certain theoretical and mathematical problems associated with the averaging process that is the basis of this method. These would have to be minimized, to the extent possible, in any rule based upon this method.

B. Flat Charge Per Project

Under this method, all licensees using Government dams would be assessed the same charge. This approach would be easily administered and would, in one way, treat all licensees uniformly.

The disadvantages of this method are substantial. The annual charge would not depend on the specific characteristics of a project and would not be proportioned to the value conferred by the Government dam. Also, the proportion of the charge to the value conferred would be different for each project. This would require additional justification. Setting a low charge would be essential to avoid discouraging the development of hydro project with more marginal levels of benefits. This would not provide a reasonable return to the United States. If the annual charge were set higher, the resulting disincentive to develop marginally economical projects would be contrary to section 10(e) of the FPA and to the Commission's other statutory obligations to encourage hydropower development.[75]

C. Sharing of the Benefits Based on Actual Revenues (Royalty Method)

This method would calculate a licensee's "actual" annual net benefit using yearly cost, revenue, and tax data from the licensee's own records together with regional data on electric utility running costs and firm power rates. The annual charge would be a fixed percentage share of this "actual" benefit.

Under this method, there would be no need to forecast the value of benefits conferred over the life of the project since the charge would be based on actual benefits received, measured in current year dollars. The method would reflect the effect of inflation and the changes in the value of electricity. The charge is likely to be low in early years, but would grow over the term of the project license, approximately tracking project net revenues. Over the project life, the aggregate value of the charges would approximate the specified share of the aggregate net benefit conferred.

This case-by-case approach, however, would involve a substantial burden each year on the Commission and on all licensees of projects at Government dams. The effort necessary to administer an actual benefit (or royalty) method, perhaps even in a single year, could easily be more than a one-time effort to determine annual charges based on an estimated net benefits approach. Each project would have to be reanalyzed every year, rather than being analyzed only once as a newly-licensed project.

A royalty charge based on actual revenues also depends considerably on a licensee's own business and management ability. Thus, the value of the hydropower resource would become less significant in setting the annual charge. Another disadvantage stems from the need to monitor and calculate actual revenues and costs on a yearly basis. At a minimum, significant recordkeeping and reporting requirements would be imposed on the licensee. Aside from this regulatory burden on licensees, the public availability of the necessary financial data could be a source of concern to private developers who consider such information to be proprietary and confidential.

Some other problems are inherent in this approach. Where a private developer sells the entire project output to an electric utility, the net income of a project after taxes can be calculated. However, where a developer itself uses some or all of the project output, the Commission would be forced to impute revenues and a net return. While prevailing purchase rates for that project or similar projects could be used, any estimates would be controversial, particularly if not done in a standard and consistent way. The Commission believes the need to perform these types of estimates leads to difficulties that are more significant than would be present in the method proposed in this Notice.

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[73] The average cost can be calculated by using Department of Energy-Energy Information Administration (EIA) data and from tables in EIA's *Statistics of Privately-Owned Electric Utilities*, which shows total thermal plant production expenses and total kilowatt hours produced.

[74] This determination would, in part, involve finding the average plant capacity factor, average operation and maintenance costs, and average fixed costs for groups of such hydroelectric power plants at various net benefit levels. This method would also require estimation of the relative contribution of each group to the aggregate net benefits of all projects.

[75] City of Vanceburg v. FEPC, 571 F. 2d 630 (D.C. Cir. 1977). Section 632 of the Energy Security Act of 1980, Pub. L. 96-294, 94 Stat. 611. Section 405 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2705.

D. Codification of the Current Case-by-Case SNB Method

Fixed, current dollar annual charges have been traditionally established at the time of licensing on a case-by-case basis using the four-step SNB method. One option is to retain this traditional method and to codify it in the regulations. However, case-by-case application of the SNB method is not viewed as an acceptable approach. To determine both project power costs and the value of the least costly power from an alternative source, the SNB method requires individual, project-by-project estimates of project construction costs, long-term inflation rates, applicable interest rates, fuel costs, utility power purchase rates, O&M costs, and so on. All of these items cause considerable controversy in many licensing proceedings. The result is that substantial Commission staff time is consumed in fixing the annual charges to be included in a project license. There is also no absolute assurance of uniformity between individual licensing proceedings in setting the annual charges. Moreover, a developer planning a project has significant difficulty in estimating in advance what the annual charge will be. Even though the traditional detailed examination of the specifics of each case has the potential for most accurately reflecting local conditions in measuring the net benefit of each individual project, it cannot adequately account for the uncertainties of future rates of inflation or deflation. As a result, these inherent disadvantages militate against codifying this case-by-case methodology.

VII. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601–612) requires agencies to prepare certain statements, descriptions, and analyses of proposed rules that, if promulgated, will have a significant economic impact on a substantial number of small entities. The Commission is not required to make such analyses if a proposed rule will not have such an impact.

Most electric utilities and many hydroelectric developers do not fall within the RFA's definition of small entity.[illegible]

In addition, out of a total of 796 hydroelectric project licensees, only 41 licensees (5%) are involved with projects using Government dams and other structures. Similary, out of a total of 875 pending hydro license and permit applications, only 117 (13%) are for projects using Government dams. These figures reveal that this rule would not affect a substantial number of small entities even among those now subject to Commission jurisdiction. This is even more evident when measured against the large number of potential hydroelectric applicants that might seek Commission licenses.

The economic impact on licensees from this rule is also not likely to be significant. First, there is no assurance that any annual charge would be significantly different in amount from that imposed through the present adjudicatory approach. Second, the sharing of the net benefits necessarily implies that economic benefits, over and above project costs, are being split equitably between the United States and the developers pursuant to section 10(e) of the Federal Power Act. Third, the proposed rule will help to alleviate some of the uncertainty for licensees when making financial decisions. Fourth, the resources now spent in individual licensing proceedings would be saved. Fifth, the use of a yearly inflation adjustment factor will eliminate possibly significant miscalculations in forecasting inflation trends, and will ensure that inflation or deflation is properly taken into account when the annual charges are billed each year. Finally, the deferral option will lessen the burden on licensees for the first, less profitable years of project operation. For these reasons, the Commission does not believe that the economic impact of this rule will be "significant," at least within the meaning of the RFA.

Pursuant to section 605(b) of the FRA, therefore, the Commission certifies that this rule, if promulgated, will not have a "significant economic impact on a substantial number of small entities."

VIII. Finding of No Significant Environmental Impact

Pursuant to section 102(2)(C) of the National Environmental Policy Act of 1989, 42 U.S.C. 4332(C), the Commission finds that this rule, if promulgated, would not significantly affect the quality of the human environment. A developer's decision to proceed with a project using a Government dam is based upon an estimate of the value of the power produced versus the cost of producing that power. If the value exceeds the costs involved, the developer will, absent other constraints, most likely decide the project is economical and will build it. The developer is not likely to be dissuaded by the annual charge to the Government, since the developer will still realize 50% of the ecomomic benefits from the project. Project size, site characteristics, and the cost of available, alternative sources of power will be the critical factors in the decision to build or not build a given project. The generic methodology proposed in this rule seeks to provide procedures designed to identify and quantify these factors. The rule does not itself affect the decision to construct a project.

As a result, this proposed rule does not significantly affect quality of the human environment. Consequently, the Commission does not believe that an Environmental Assessment or an Environmental Impact Statement needs to be prepared for this proposed rule. Of course, an appropriate environmental analysis, include possibly an EA or EIS, will continue to be made in connection with individual project applications filed with the Commission.

IX. Public Comment Procedure

The Commission invites interested persons to submit written data, views, and other information concerning matters set out in this Notice. The Commission is particularly interested in receiving comments from the Department of the Interior, the Army Corps of Engineers, and the Bureau of Reclamaton. All comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should refer to Docket No. RM83-13-000. An original and 14 copies should be filed. Comments must be received by the Commission no later than May 16, 1983. The Commission does not contemplate any extension of this comment period.

All written comments will be placed in the Commission's public file and will be available for public inspection during regular business hours at the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

[illegible] 5 U.S.C. 601(3) *citing to* section 3 of the Small Business Act, 15 U.S.C. 632 (Supp. IV 1980). Section 3 of the Small Business Act defines a "small-business concern" as a business which is independently owned and operated and which is not dominant in its field of operation. *See also* SBA's Small Business Size Standards, 13 CFR Part 121 (1982).

List of Subjects

18 CFR Part 4

Electric Power, Reporting and recordkeeping requirements.

18 CFR Part 11

Electric power.

(Federal Power Act, as amended, 16 U.S.C. 792–828c (1976); Department of Energy Organization Act, 42 U.S.C. 7101–7352 (Supp. IV 1980); E.O. 12009, 3 CFR 142 (1982); 5 U.S.C. 553 (Supp. IV 1980).)

In consideration of the foregoing, the Commission proposes to amend Parts 4 and 11, Title 18, Chapter 1, Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 4—LICENSES, PERMITS, EXEMPTIONS, AND DETERMINATION OF PROJECT COSTS

Subpart A—Determination of Cost of Projects Constructed Under License

1. Section 4.1(a) is revised to read as follows:

§ 4.1 Initial cost statement.

(a) *Notification of Commission.* Except for projects subject to § 11.22 which use Government dams or other structures owned by the United States, if a project is constructed under a license issued under the Federal Power Act, the licensee must, within one year after the project is available for service, file with the commission a letter, in quadruplicate, declaring that the original costs have been recorded in compliance with the Commission's Uniform System of Accounts and the books of accounts are ready for audit. For projects governed by § 11.22, the licensee must file the letter required under this section within nine months after the project is available for service and must also meet the requirements in § 11.22(d) (4) and (e).

* * * * *

2. In Part 11, the table of contents is amended by revising the title of § 11.22 and adding a new § 11.22a, to read as follows:

PART 11—ANNUAL CHARGES UNDER PART I OF THE FEDERAL POWER ACT

Sec.

* * * * *

11.22 Annual charges for use of Government dams or other structures under section 10(e) of the Act, excluding pumped storage projects.

Sec.

11.22a Annual charges for pumped storage projects using Government dams or other structures and for use of tribal lands.

* * * * *

3. Section 11.22 is revised to read as follows:

§ 11.22 Annual charges for use of Government dams or other structures under section 10(e) of the Act, excluding pumped storage projects.

(a) *Applicability.* This section applies to any non-Federal hyroelectric power project, except for pumped storage projects, that uses for electric power generation a dam or other stucture owned by the United States.

(b) *Definitions.* For purposes of this section, the following definitions are applicable:

(1) "Annual Capacity Factor" or "ACF" means, for a hydropower project, the ratio resulting from dividing the average annual generation expected from the project (in kilowatt hours) by the product of the hours in a year (8760) and the project's installed capacity (in kilowatts).

(2) "Annual Capacity Factor Thermal" or "ACFT" means, for a thermal generation alternative, the ratio resulting from dividing the average maximum generation expected from the thermal alternative (in kilowatt hours) by the product of the hours in a year (8760) and the thermal alternative's installed capacity (in kilowatts).

(3) "Construction cost" means the total investment directly related to placing a generating unit in service. For licensed projects, this includes the items in Account Nos. 330–335 and 350–359 in the Commission's Uniform System of Accounts, 18 CFR Part 101.

(4) "Fixed Operating Costs" or "FOC" means the fixed operation, maintenance, administrative, and other general costs which do not vary with the amount of electricity produced. These costs are included in (as appropriate) Account Nos. 500–14, 535–45, and 546–54 in the Commission's Uniform System of Accounts 18 CFR Part 101.

(5) "Government dam" means a dam or other structure owned or constructed by the United States, or an agency thereof, for Government purposes with or without financial contributions or repayments by others.

(6) "Levelized" means the conversion of a series of varying costs or benefits for a number of sequential time periods into a uniform series of costs or benefits over the same number of time periods, where the uniform series of costs or benefits have the same total present value as the varying series. For this rule, levelization will be for the period from the time when the project is available for service until the end of the term of the license.

(7) "Licensee" means any person, state, or municipality licensed under the provisions of Part I of the Federal Power Act, and any assignee or successor or interest thereof.

(8) "Net Benefit" or "Net Benefits" means the difference between the cost of power produced at the licensed project and the cost of equivalent wholesale electric power produced by the least costly alternative source(s).

(9) "Operation and Maintenance Costs" or "O&M" means the variable operation and maintenance costs for generating electricity that depend on the amount of electricity produced. These are included in Account Nos. 500–14, 535–45, and 546–54 of the Commission's Uniform System of Accounts, 18 CFR Part 101.

(10) "Peak Season" or "Peak Load Season" means the three-month period in which a region's electric power system or systems experience the maximum seasonal electric demand.

(11) "Peak Season Capacity Factor" or "PSCF" means, for a hydropower project, the ratio resulting from dividing the average generation expected to be produced in the peak load season (in kilowatt hours) by the product of the number of hours in the peak load season and the project's installed capacity (in kilowatts).

(c) *General Rule.* (1) Except as otherwise permitted under subparagraph (c)(2), any licensee whose licensed, non-Federal project uses a Government dam for electric power generation must pay the United States an annual charge for use of such dam, as determined in accordance with this section. Payment of such annual charge is in addition to any reimbursement paid by a licensee for costs incurred by the United States as a direct result of the licensee's project development at such Government dam.

(2) Any licensee that is obligated under the terms of a license, issued on or before [*insert the effective date of this section*], to pay specified annual charges for the use of a Government dam must continue to pay the annual charges prescribed in the project license, pending any readjustment of the annual charge for the project under this section made pursuant to section 10(e) of the Federal Power Act.

(d) *Computation of Annual Charge.* The annual charge for each licensed project that uses a Government dam will be determined according to the terms of this paragraph.

(1) *Annual Charge.* The annual charge is fifty percent (50%) of the Annual Net

Benefit (ANB) computed for the project under subparagraph (c)(2). subject to an inflation adjustment. The inflation adjustment will be established each year by the Commission based upon the Gross National Product Deflator for that year, as determined by the United States Department of Commerce.

(2) *Annual Net Benefit* (ANB). (i) The ANB shall be calculated as the difference between the Annual Power Value (APV) and the Annual Project Power Cost (APPC).

(ii) The ANB is the levelized annual amount equivalent to the aggregate present worth of project net benefits from the time the project becomes available for service until the end of the license term. The ANB will be stated in constant dollars as of the year in which the project becomes available for service.

(iii) Except for relicensed projects and for readjustments of any annual charge, the ANB is determined for each licensed project as of the year the project becomes available for service (completion of construction) in accordance with the applicable regional APV established by the Commission under subparagraph (c)(3). For relicensed projects and for readjustments of any annual charge, the ANB is determined, respectively, as of the year in which the relicensing or readjustment proceeding is begun.

(3) *Annual Power Value* (APV). The APV is the annual levelized cost of equivalent electric power provided by the least costly regional alternative source or sources.

(i) The APV is the sum of two components: a Capacity Value (CV) component and an Energy Value (EV) component.

(A) The CV component is determined by the following formula:

$$CV = \frac{(I \times R) + FIC + FOC}{ACF \times 8760} \times 100 \times PSCF \times MAF$$

where

CV = Levelized capacity value of the project (in cents per kWh).

I = Investment (construction cost) of least costly alternative generating unit completed in the same year as the project (in dollars per kW of capacity).

R = Annual fixed charge rate (decimal).

ACF = Annual capacity factor of project (decimal).

FIC = Annual levelized cost of fuel inventory for thermal alternative (in dollars per kW of installed capacity).

FOC = Annual levelized fixed operating costs for thermal alternative (in dollars per kW of installed capacity).

PSCF = Capacity factor of project during peak load season (decimal).

MAF = Mechanical availability factor (decimal).

(B) The Energy Value component is determined by the following formula:

$$EV = (F \times HR \times 10^{-6}) + O\&M + EV_a \text{ if } Z \geq 1.0,$$

or

$$EV = [(F \times HR \times 10^{-6}) + O\&M](Z) + EV_m \times (1 - Z) \text{ if } Z < 1.0$$

where

EV = Levelized total energy value (in cents per kWh).

F = Levelized cost of fuel (in cents per million Btu).

HR = Heat rate of thermal alternative generating unit (in Btu per kWh).

10^{-6} = Conversion factor.

O&M = Levelized variable operating and maintenance costs of thermal alternative (in cents per kWh).

EV_a = Energy value adjustment, computed in accord with procedures described in United States Dep't of Energy, Federal Energy Regulatory Commission, *Hydroelectric Power Evaluation* (DOE/FERC-0031 August 1979).

EV_m = Levelized annual average system incremental cost of energy or system lambda (in cents per kWh).

Z = Maximum expected annual generation of alternative, divided by expected annual generation of project, expressed as

$$\frac{MAF \times ACFT \times PSCF,}{ACF}$$

MAF = Mechanical availability factor, expressed as

$$\frac{\text{1-EFOR of hydro unit}}{\text{1-EFOR of thermal unit}}$$

EFOR = Equivalent forced outage rate for type of generation.

(4) *Annual Project Power Cost* (APPC). The Annual Project Power Cost (APPC) is the annual levelized cost of power, including fixed charges, operation, maintenance, and administrative costs of the project. Construction costs, a principle part of fixed charges, are determined by the Commission after examining the cost statement submitted by a licensee pursuant to § 11.22(e), as verified by an independent certified public accountant. Any variance between this cost statement and the amounts recorded in Account Nos. 330–335, 350–359, and 389–399 of the Uniform System of Accounts, 18 CFR Part 101, will be resolved by the Office of the Chief Accountant or, if necessary, by the Commission. Project operation, maintenance, and administrative costs will be estimated by the Commission using licensee-supplied estimates, if any, and generalized cost data for hydropower projects.

(5) *Nominal Annual Charges.* Prior to the time a project becomes available for service and the annual charge is determined under paragraphs (c)(1) through (c)(4) of this section a nominal annual charge of one hundred dollars will be billed to the licensee.

(e) *Licensee Cost Statement.* In connection with all licenses issued after [*insert effective date of this section*], for projects using Government dams, the licensee shall prepare and submit, within nine months after project construction is complete, a statement detailing the total actual legitimate cost of constructing the project. This statement must contain a listing of the claimed amounts which are recorded in Account Nos. 330–335, 350–359, and 389–399 in the Commission's Uniform System of Accounts, 18 CFR Part 101. This statement must also be verified by an independent certified public accountant, who must certify that the claimed construction cost conforms in all material respects to the requirements of the Commission's Uniform Systems of Accounts.

(f) *Method of payment.* (1) Any licensee required to pay an annual charge under this section must submit payment according to this paragraph and the terms of the annual billing given to the licensee pursuant to § 11.31 of this chapter. The annual billing will reflect an annual charge computed in accordance with this section.

(2) If, during any of the first ten years following the issuance of the project license, the net revenues from project operation for a given year are less than the billed annual charge for that year, the project licensee may, at its option,

defer payment of the annual charge as follows.

(i) The licensee must request payment deferral under this subparagraph not later than 45 days after the rendition of the annual charges bill. Any payment deferral request must be accompanied by a supporting statement from an independent certified public accountant verifying that project net revenues for the current year do not exceed the billed annual charge for that year. No requests for deferral will be accepted after the first ten years following the issuance of the project license.

(ii) Upon receipt of a deferral request and supporting statement, the Commission will defer the annual charge payment until after the tenth year of the project license.

(iii) After the tenth year of the project license, a bill will be rendered for both the payment of any deferred annual charges, plus interest for the period of deferral, and the annual charge for the eleventh year of the project license.

(iv) If a licensee obtains deferral of more than one annual charge payment under this paragraph, the licensee may request that the Commission bill these other deferred payments, plus interest for the period of deferral, on a graduated basis in the year or years following the tenth year of the project license. No payment may be deferred beyond the twentieth year after the project license is issued.

(v) No deferral will be allowed for nominal annual charge payments billed prior to the time the project becomes available for service.

(3) The interest rate on any annual charge payments deferred under paragraph (e)(2) of this section is the rate determined under 18 CFR 35.19a(a)(2)(iii).

(4) Any licensee that receives a billing for annual charges under this paragraph must pay the billed amount on or before 45 days after the date on which the Commission renders the bill.

(5) If a licensee makes an estimated annual payment or payments before a bill is rendered, the licensee's next bill will include an adjustment of the payment amount that reflects any overpayment or underpayment.

4. Part 11 is amended by adding a new § 11.22a, to read as follows:

§ 11.22a Annual charges for pumped storage projects using Government dams or other structures and for use of tribal lands.

In accordance with section 10(e) of the Federal Power Act, the Commission will determine, on a case-by-case basis, the annual charges for any pumped storage project using a Government dam or other structure and for the use of tribal lands within Indian reservations.

5. Section 11.28 is revised to read as follows:

§ 11.28 Effective date.

All annual charges, except those imposed under section 10(f) of the Federal Power Act, will commence upon the effective date of the license unless some other date or dates are fixed in the license.

6. In § 11.31, paragraph (a) is revised to read as follows:

§ 11.31 Time for payment, protest or request for hearing; penalties.

(a) *Payment of annual charges.* Unless otherwise permitted under § 11.22, annual charges (except those for headwater benefits) must be paid within 45 days of rendition of a bill therefor by the Commission. Annual charges for headwater benefits must be paid within 60 days of the date on which the Commission renders a bill therefor.

* * * * *

[FR Doc. 83-[illegible] Filed 4-6-83; 8:45 am]

BILLING CODE 6717-01-M

DEPARTMENT OF THE TREASURY

Customs Service

19 CFR Part 10

Proposed Customs Regulations Amendment Relating to the Generalized System of Preferences

AGENCY: Customs Service, Treasury.

ACTION: Proposed rule.

SUMMARY: This document proposes to amend the definition of the term "imported directly," to expand that definition to allow treatment under the Generalized System of Preferences ("GSP") for eligible articles which: (1) Originate in a beneficiary developing country, (2) are shipped to a developed country and auctioned there, and (3) then shipped to the United States.

By allowing those eligible articles to be entered free of Customs duty, the beneficiary developing countries of which they are products, would obtain the intended benefit established by the GSP.

DATES: Comments must be received on or before May 9, 1983. A comment period of only 30 days is being provided for this proposal in order that a decision may be made in time to be effective prior to the next annual sale of Cameroon Tobacco in June of 1983.

ADDRESS: Comments (preferably in triplicate) should be addressed to the Commissioner of Customs, Attention: Regulations Control Branch, U.S. Customs Service, 1301 Constitution Avenue, NW., Washington, D.C. 20229.

FOR FURTHER INFORMATION CONTACT: Paul Giguere, Classification and Value Division, U.S. Customs Service, 1301 Constitution Avenue NW., Washington, D.C. 20229 (202-566-8234).

SUPPLEMENTARY INFORMATION:

Background

Title V of the Trade Act of 1974, as amended (19 U.S.C. 2461-2465), authorizes the President to establish a Generalized System of Preferences (GSP) to provide duty-free treatment for eligible articles imported directly from designated beneficiary developing countries (BDCs). BDCs and articles eligible for GSP treatment are designated by the President by Executive Order in accordance with the provisions of the Trade Act. The Customs Regulations issued to administer the GSP are contained in §§ 10.171-10.178 (19 CFR 10.171-10.178).

By Executive Order 12311 of June 29, 1981, the President first extended GSP treatment to "wrapper tobacco." Wrapper tobacco is that quality of leaf tobacco which has the requisite color, texture, size, and burn, to be suitable for cigar wrappers. However, counsel for the Cigar Association of America, Inc., has informed Customs that "Cameroon wrapper" tobacco, grown in the United Cameroon Republic and the Central African Republic (both BDCs), cannot obtain the benefit of GSP because, under normal marketing procedures, the entire production of wrapper tobacco from these countries is shipped to France (not a BDC) where it is sold at auction and some is later exported to the United States. While in France, the bulk of the wrapper tobacco is held in bonded warehouse at the port of Le Havre, as the actual auction of the product by lot on the basis of sample bales, is held in Paris. The warehoused wrapper is subject to no manipulation or processing other than fumigation and preparation for shipment (*i.e.*, reloading) after sale. Furthermore, the wrapper tobacco does not enter the commerce of France, except for the sale at auction.

Section 503 of the Trade Act of 1974, as amended (19 U.S.C. 2463), provides that duty-free treatment of articles designated eligible for GSP shall apply only "to an article which is *imported directly* from a beneficiary developing country into the customs territory of the United States, * * *," (emphasis supplied). The term "imported directly" is defined in § 10.175, Customs Regulations (19 CFR 10.175), to mean a

Official Committee File

Allegheny
ELECTRIC COOPERATIVE, INC.
212 LOCUST ST. P.O. BOX 1266 • HARRISBURG, PENNSYLVANIA 17108-1266 • PHONE 717 233-5704

July 22, 1983

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
JUL 25 1983
WASHINGTON, D.C. 20510

Honorable James A. McClure, Chairman
Committee on Energy and Natural Resources
United States Senate
Room 360, Dirksen Building
Washington, D.C. 20510

Attn: Howard Useem

Dear Senator McClure:

It is my understanding that the Committee will consider S. 1132 at its July 25, 1983 meeting. This legislation, of course, addresses the issue of the annual charges made for the use of government dams by non-federal hydro power developers. The bill seeks to clarify a proposed ruling of the Federal Energy Regulatory Commission (FERC).

On behalf of the over 600,000 farmers and other rural residents who are served by Pennsylvania's nonprofit, consumer-owned rural electric cooperatives, I would like to express our support for this important legislation. We believe the future development of small-scale hydroelectric generating facilities in the United States could suffer great harm if this legislation is not enacted.

As a leading developer of small-scale hydroelectric generating facilities in Pennsylvania, we are deeply concerned about this issue. We have two primary concerns.

First, we are concerned that the FERC ruling will lead to excessive charges by the federal government to non-federal developers who build hydroelectric generating projects on government dams. Our studies have shown that many small-scale hydroelectric projects are marginal at best. To significantly and unreasonably increase the annual charge would severely lessen the feasibility of many projects now under consideration. The federal government's stated policy is to decrease our dependence on imported petroleum by fostering the development of renewable energy resources such as hydroelectric generation. Increasing the annual charge would run directly counter to this stated policy.

Second, the FERC ruling does not provide sufficient information for determining the amount of the annual charge. Under the FERC ruling, the amount of the annual charge made to a developer for a specific project could vary widely. As a result, developers will be unable to accurately weigh the costs associated with a project. Hydro power development is already an uncertain business. We should not allow federal government policies to add to this uncertainty.

I am enclosing a copy of a resolution passed by our sister organization, the Pennsylvania Rural Electric Association, on this issue. In addition, I am enclosing a copy of the comments we made to FERC on this issue. We would appreciate having these items added to the Committee's record of its consideration of S. 1132.

In conclusion, we urge the Committee to expeditiously and affirmatively consider S. 1132.

Very truly yours,

William F. Matson

William F. Matson
President

WFM:jd

cc: Honorable John Heinz
Honorable Bill Bradley
Honorable Arlen Specter

Statement
of the
Association of California Water Agencies
on
S. 1132
presented to the
Committee on Energy and Natural Resources
United States Senate

July 25, 1983

The Association of California Water Agencies appreciates this opportunity to support S. 1132, a bill to specify the annual charges for hydroelectric projects with licenses issued by the Federal Energy Regulatory Commission for the use of Federal dams and other structures. This issue, which has delayed the construction of a number of hydroelectric projects, needs resolution and S. 1132 represents the most equitable answer both for our national interest and that of local sponsors of these projects.

The Association represents almost 300 local public agencies and cities that serve 90 percent of the surface waters consumed in the agricultural and urban areas in California. Many of our members contract for all or a portion of their water supplies from federal projects located throughout the State and have been discussing the construction of hydroelectric units with the federal agencies managing these projects.*

During the past decade, American dependence on foreign energy supplies has been widely discussed and the necessity of reducing this dependence has become a national goal. This has spurred increased attention to all energy sources including the development of the hydroelectric potential at dams and other facilities.

Presented by Robert P. Will, Washington Counsel

Simplification and revision of licensing procedures at the Federal Energy Regulatory Commission, regulation of electric utilities with respect to the purchase of power from non-utility developers of these projects, tax incentives and broader utilization of tax exempt bonds all reflect the intent of Congress to promote their development. Federal water project agencies, due to budget constraints and other factors, have been slow in undertaking this development and many local public agencies have the capability of constructing and operating these facilities and will do so if a fair and equitable means of reimbursing the United States for any costs it incurs as a result of their activity is adopted.

Most of the proposals advanced to date, including that of the Federal Energy Regulatory Commission this spring, have suggested highly sophisticated and theoretical approaches for the determination of charges. These complex formulas will discourage nonfederal sponsors of these projects from proceeding with their consideration. The desirability of a simple, fixed formula which will permit ease of long range financial planning as in S. 1132, will help promote the development of these projects. As many of these local sponsors do not have large financial resources, the need for certainty and a fixed federal policy is essential. S.1132 will also greatly ease administrative burdens both for the federal government and the nonfederal sponsors.

Most of our members who are considering undertaking these projects are also contractors with the United States for a water supply from these projects and have been reimbursing the costs of the project allocated to them under Reclamation Law. These cost allocations, in most instances, were made without consideration of the dam's hydroelectric potential which usually lowers the costs allocated to other purposes. As a matter of equity, the revenues derived by the United States over any costs actually incurred should be held to levels which do not result in an unfair duplication of charges to the local agency. The Association supports S. 1132 as a fair resolution of this issue.

S. 1132, in our opinion, is a highly desirable approach for charges for these projects. It permits the United States to share in the revenues to be derived, it will encourage the development of these highly necessary and environmentally desirable projects and promotes ease of administration. We urge your adoption of S. 1132.

DODSON [redacted] Irrigation District P.O. Box R Malta, Montana 59538
Phone 654-1440

July 13, 1983

Mr. Howard Useem
Senate Energy & Natural Resources Committee
Dirksen Senate Office Building
Washington D. C. 20510

Dear Mr. Useem and Committee Members:

We wish to go on record as being in support of Senate Bill #1132 on the falling water charge and request passage of this legislation.

The present rates proposed by the Department of Interior and Bureau of Reclamation for annual charges for use of government Dams are excessive, and would discourage participation by non-Federal interests in development of Hydro power.

We feel that passage of Senate Bill #1132 would help stabilize further hydro power development.

Sincerely yours,

DODSON IRRIGATION DISTRICT

Victor J Nicholson
President J.S.

UTAH COLO.
ARIZ. N.M.

CITY OF FARMINGTON, NEW MEXICO
ELECTRIC UTILITY DEPARTMENT

505 / 327-7701
505 / 327-7711
Ext. 1160

JUL 11 1983

July 6, 1983

Senator James A. McClure
Chairman
Committee on Energy and Natural Resources
Dirkson Office Building
Room 361
Washington, D. C. 20510

Dear Senator McClure:

Re: Comments Concerning the FERC Notice of Proposed Rulemaking - Annual Charges for Use of Government Dams and other Structures Under Part 1 of the Federal Power Act

Please find enclosed one copy of the City of Farmington's comments submitted to the Federal Energy Regulatory Commission in response to the notice of proposed rulemaking - Annual Charge for Use of Government Dams and Other Structures Under Part 1 of the Federal Power Act (FERC Docket No. RM 83-13-000 March 31, 1983). These comments are provided for entry into the record in support of Senate Bill 1132 which is scheduled for hearing on July 26, 1983.

As indicated in our comments, we feel that FERC should carefully consider a flat charge based on dependable capacity and actual generation as proposed in this Bill.

Very truly yours,

W C Lewis
W. C. Lewis
Electric Utility Director

WCL:MB
Enclosure (1)

CC:W/Enc. Howard S. Useem, Professional Staff Member
Subcommittee on Energy and Natural Resources
3202 Dirkson Office Bldg.
Washington, D. C 20510

Ann Marie Gibbons, APPA
Washington, D. C. 20037

George V. Nielsen, R. W. Beck & Associates
Seattle, WA 98101

P.O. BOX 900, 87401

BEFORE THE FEDERAL ENERGY COMMISSION
COMMENTS SUBMITTED IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING - ANNUAL CHARGES FOR USE OF GOVERNMENT DAMS AND OTHER STRUCTURES UNDER PART 1 OF THE FEDERAL POWER ACT
(FERC DOCKET NO. RM 83-13-000, March 31, 1983)

1. INTRODUCTION AND OVERVIEW

The following comments have been prepared by R. W. Beck and Associates in response to the above-referenced Notice of Proposed Rulemaking (NOPR) in which the Federal Energy Regulatory Commission (FERC) proposes to retain "sharing-of-the-net-benefits" as the basis for determining annual charges, but also proposes to replace the currently-used case-by-case determination of net benefits with a generic formula-based approach. Our analysis of the NOPR weighed the FERC's proposed procedures against the requirements of Section 10(e) of the Federal Power Act, as interpreted and established by the Court in the City of Vanceburg vs. FERC (571 F.2d 630), and against our own belief that any method for assessing annual charges must be equitable, specific, and easily applied. Our analysis begins with a specific discussion of the limitations of the proposed method for calculating net benefits followed by: a critique of the "sharing-of-the-net-benefits" approach for assessing the annual charge; a discussion of alternative methods for assessing annual charges and the NOPR's compliance with the National Environmental Policy Act (NEPA); and our specific conclusions and recommendations.

2. PROPOSED METHOD FOR DETERMINING NET BENEFITS

This rule purports to be a new methodology. In fact, it is not. It is the sharing-of-the-net-benefits method FERC has always used with a formula approach designed solely to facilitate FERC staff review. Sharing-of-the-net-project-benefits is the principle used by FERC to justify the equitability of its proposed method for computing annual charges. For FERC's proposed method for assessing annual charges to be equitable, the calculated net project benefits must accurately and realistically mirror the actual benefits realized by the hydropower developer. Although this fact is implicitly acknowledged by the FERC ("Measurement of project "net benefits" is, therefore, the critical and fundamental task that lies at the heart of this approach."(I)), our analysis indicates that the procedures outlined for determining project costs and power values may lead to an overestimation of net project benefits in some cases and an underestimation in others. In essence, the proposed method for determining net benefits will result in an inequitable annual charge on a case-by-case basis.

a. Project Cost Determination

In the Introduction (I) of the NOPR, FERC defines net benefits as "the difference between the estimated value of the power produced at the project (equal to the cost of producing equivalent power with the least costly sources of power) and the estimated costs of producing project power" (emphasis added). Thus, for the net benefit determination to be accurate, the calculation of project costs must include all of the costs realized by the hydropower developer. However, certain language in the proposed rulemaking implies that FERC may exclude certain costs associated with development of a hydropower project from the project cost determination: "Section 10(e) payments ... are intended to value economic benefits conferred by the Government by looking at the least costly alternative source of power and the project powerhouse costs (excluding any consideration for construction costs associated with the dam)." (Section V.H., emphasis added.) FERC claims that the proposed method will be more accurate because actual project construction costs, rather than construction cost estimates, will be used. However, an accurate determination of project costs cannot be made if real costs are excluded, even if those costs deemed to be allowed in the calculation are defined precisely and accurately.

(1) Exclusion of Front-End Contributions to Federal Constructing Agency

In some cases, applicants for license and licensees have made payments, or contracted to make payments, for a portion of the construction costs of the Government dam. The NOPR states that payments to the U.S. Bureau of Reclamation (USBR) cannot be credited against a licensee's billed annual charges because "The USBR payments are normally designed to repay the costs of construction of the dam or for other benefits not related to power produced at the dam.". This language appears to imply that, even when payments to the USBR are made for construction of facilities necessary for the development of a hydropower project (i.e., the conduit), those payments will not be considered in the assessment of annual charges (Section V.H.). While a direct credit of such payments to the USBR against the annual charge may not be appropriate, some method of accounting for these payments in the project cost determination must be made. To do otherwise would, in effect, result in a "double charge" to the licensee for dam construction: one clearly defined charge to the USBR and one hidden charge (roughly equivalent to 50% of the USBR charge) imbedded in the FERC's annual charge assessment. Although the proposed rulemaking states that Account Nos. 330-335, 350-359, and 389-399 (18 CFR Part 101) are to be used in determining the construction cost and Account No. 332 covers the cost of reservoirs, dams, and waterways, it is not clear if payments to the USBR for dam construction will be allowed in this account.

(2) Exclusion of Other Items From the Project Cost Determination

In addition to the specific issue of payments to the USBR, the language in Section V.H. of the NOPR, which defines project costs only in terms of "project powerhouse costs", appears to exclude other real costs incurred by a developer from the project cost determination. Project costs should be all inclusive and recognize the allocated cost of requisite facilities for hydropower development, including costs associated with required measures to protect and mitigate for project-caused adverse impacts on environmental resources. Although Account Nos. 330-332 (18 CFR Part 101) allow for the cost of facilities and lands for fish and wildlife and recreation, it is not clear if other environmental mitigation measures can be included in the construction cost determination. (It should be noted that Section IV.A.3.(a) of the NOPR appears to imply that the costs of environmental mitigation are included in the regional alternative cost when it is stated that: "full environmental control of stack emissions and cooling water is assumed".)

(3) Estimated Operation and Maintenance Costs

Although the FERC has stated that "licensees will be given an opportunity to submit their own O&M cost estimates" (III.C.), the FERC has also indicated that the licensee's estimates might not be used if "they depart significantly from reasonable forecasts based on standard industry data" (Section III.C.). Judging a licensee's O&M estimates against standard industry data and forecasts, which are likely to be based on generalized or "average" situations, will not account for the significant variability of an O&M from one project to another. Furthermore these generalized data are likely to be incomplete and inaccurate or, at times, non-existent. For those projects requiring costly, long-term mitigation (i.e., construction of recreation facilities after the project is operational), the actual O&M costs (annual costs above and beyond debt service) are likely to be significantly higher than average. If, in such a case, the licensee's own estimate of O&M costs was rejected by FERC, the resulting project cost and net benefits determinations would not truly reflect the licensee's long-term development costs, and the annual charge would tend to be overestimated. Furthermore, mixing reasonable forecasts of O&M with actual construction costs to determine the cost to produce the power is inconsistent in terms of significance and confidence limits.

(4) Use of Actual Construction Costs - Precision of the Project Cost Determination

FERC states that the proposed use of actual hydropower project construction costs will "eliminate the uncertainties associated with using estimated project construction costs" (Section I.A.). However, the other major element of the net benefit equation, regional power value, is highly uncertain in that it includes only average estimates of important future conditions: fuel price, fuel price escalation, power generation, etc. Furthermore, the apparent exclusion of certain items from the project cost determination (i.e., payments to USBR) is inconsistent with the precision associated with using actual project construction cost data. In short, it is a misconception that using actual construction cost data will increase the accuracy of the net benefit determination and the equitability of the annual charge, while at the same time the power value determination is highly uncertain and certain real costs to the licensee are excluded fom the project cost determinations.

b. Power Value Calculation

The proposed method for calculating power values contains a number of assumptions which may make the calculation easy and straightforward, but which will also tend to over-value the energy and capacity from a hydropower project at a Federal dam.

(1) Inequity of Regional versus Case-Specific Alternatives

Determination of the least expensive alternative source of equivalent power and its estimated cost on a regional basis, as proposed in the NOPR is inconsistent with the actual least cost alternative to the project which is used to establish project viability. Furthermore, it is not possible to forecast future fuel costs and fuel availability accurately on a regional basis. Even if accurate regional average data could be compiled, its use in determining an annual charge would automatically punish those developers whose real alternative costs are lower than the FERC's "averaged" regional alternative costs, resulting in an inequitable cost to be borne by the ratepayers.

In relicensing cases the inequity of the situation may be even more extreme. If the hydro project is fully depreciated, a comparison of its cost with the cost of power from a new thermal plant will result in an extremely high determination of net benefits because there is no basis for a reasonable comparison — simply put if the capacity is existing, the use of a non-existing regional alternative is not appropriate.

(2) Lack of Consideration of Project Size and Economies of Scale

Any generic approach to assigning power value runs the risk of discouraging certain projects if the economies of scale favors only projects above a certain size. If FERC is desirous of "encouraging small power projects", then it would appear equitable to elect the size limitation stated in the Public Utilities Regulating Policy Act (PURPA) for financial incentives to small power producers of 30 MW or less. FERC's proposal of a 5-MW or less cutoff point for application of the proposed rule (III.A.4.) is arbitrary and merely reflects the FERC's cutoff point for exemptible projects.

(3) Lack of Consideration of Hydro Power Plant Dependability in Assignment of Capacity and Energy Values

Capacity Value. Valuing capacity at the annualized investment, fuel inventory, and fixed O&M costs (per kW) for the alternative thermal resource is reasonable and reflects standard economic methods. However, applying that value to the average peak season capacity does not account for the fact that such capacity will not be as dependable as an equivalent thermal plant capacity. In reality, the hydro plant dependable capacity, i.e. available to meet its choice of the load under the most adverse hydrological condition, is the only capacity that is equivalent to the valued thermal plant capacity. Thus, the FERC's proposed method of using average peak period capacity overestimates the value of capacity from a hydropower resource.

Firm Energy. Similarly, firm energy must be available every year. It therefore should be that energy associated with dependable capacity and not that associated with average peak-period capacity.

Secondary Energy. Valuing secondary energy at the average marginal system energy cost assumes that there will always be a demand for that energy in the system and that the secondary energy will displace the highest-priced fuel in the system. This could lead to the paradox wherein secondary energy is of a higher value than capacity plus firm energy (Section IV). Although FERC indicates that, in the long-run, the average marginal system running cost should decrease substantially, it is highly unlikely that secondary energy, which is by definition non-dependable, would obtain such a high value in the real energy market. Furthermore, there may be no market for secondary energy if it is generated during a power surplus period especially in systems with a large hydropower resource base.

(4) Lack of Consideration of Long-Term Uncertainty

The licensee of a hydropower project at an existing Federal dam has no control over water releases, hydrologic conditions, or future upstream water uses. Although this is acknowledged by FERC (Section III.B.3.), the method proposed in the NOPR, which relies heavily on projected average annual energy, does not contain the flexibility required to accurately account for changing future conditions. Without this flexibility, some developers will clearly end up paying an inequitable annual charge.

For a given stream of benefits, those at the "front-end" are weighted more heavily than those at the "latter-end" because the "front-end" benefits are discounted over a shorter period of time. Valuing power based on the long-term average generation does not take the combined effects of the actual amount generated and the time of generation into account. For example, in those cases where a hydropower plant's annual generation increases over time because of varying hydrologic conditions, valuing power at the average annual generation could overestimate the actual benefits accrued and the power valuation would clearly penalize the developer. If the reverse was true, the proposed method might undervalue power thereby "benefitting" the developer by reducing his annual charge. In either case, the individual developer would not be truly paying for the actual benefits realized.

Actual future water allocations may also vary significantly from those projected by the developer. If future generation is reduced because of unforeseen future water withdrawals, the annual charge will be too high and the developer will not have the chance to have the charges reassessed until 20 years after the license is granted. This type of situation would be clearly punitive to such a developer.

c. Lack of Correspondence Between Proposed Method for Determining Power Value and Methods Typically Used Throughout the Project Study and Development Process/ Application of Proposed Rule to Licensing

Comparison of realistic alternatives to a proposed project is performed during project feasibility studies, project financing analyses, and in preparing the FERC License Application. The generalized, regional alternative project proposed in the NOPR will deviate from the real-world alternative analyses performed during all other phases and activities associated with a particular project. In order to place the power value calculated for the annual charge determination in perspective, a developer will be, in effect, forced to apply two methods of economic analysis: the real-world, real-alternative method, and FERC's generic alternative method. This will substantially increase the amount of effort a developer puts into project economic and financial studies.

In determining the economic feasibility of a project, the estimated development costs are compared to a least-cost alternative, which is not necessarily a thermal resource. Because this approach considers alternatives that would be actually available to a particular developer, it is more accurate than a comparison with a generic regional alternative. This type of case-specific economic analysis should be retained in the economic analysis required in the license application (Exhibit D). Should the method described in the proposed rulemaking also be required in the license application, the applicant would not have the opportunity to clearly justify project development. It is therefore requested that the FERC clarify the application of the proposed rulemaking to the licensing process.

3. SHARING NET PROJECT BENEFITS

Even if an accurate, case-specific method for determining net project benefits was adopted by the FERC, our analysis indicates that any approach for assessing annual charges that relies on a net-benefit determination will result in substantial inequities.

a. The Proposed Method and Section 10(e) of the Federal Power Act

The criteria established by the court in City of Vanceburg, Kentucky vs. FERC (571 F.2d 630) in interpreting Section 10(e) of the Federal Power Act include:

- annual charges should be set at a level that minimizes consumer costs
- should encourage power development
- should compensate taxpayers to some extent for the benefit conferred by the project license (emphasis added)

These criteria imply a relatively low annual charge. There is no basis in the Federal Power Act (Section 10(e)) for collecting substantial sums of money through the setting of annual charges. It is therefore unreasonable for the Federal government to impose high annual charges and thereby contribute to energy price inflation.

Section 10(e) of the Federal Power Act requires that a licensee pay a reasonable annual charge, the amount of which shall be set by the Commission, to recompense the United States for the use of Government dams. Section 10(e) mandates that the Commission seek to avoid increasing the price to the consumers of power by such charges (emphasis added). The word "reasonable" implies that reason is involved in setting the annual charge rate. The only reason evident in the proposed rulemaking for having an annual charge is that the Federal Power Act requires it. We contend that the intent of the Federal Power Act was not to make the determination of annual charges at Government dams an overly rigorous calculation. The proposed rulemaking fails to satisfy this intent.

b. The Proposed Method Applied to Municipal and Private Licensees

Throughout the NOPR, there appear statements that the FERC believes the NOPR to constitute "... a means to estimate, with reasonable precision, the true economic benefits of a hydro project at a Government dam." The analysis, however, fails to substantiate this point. For example, a true economic benefit would presume that the status of the Applicant should not influence the amount of benefit derived. However, for identical projects the sharing-of-the-net-benefits method actually results in higher charges to municipal licensees than to other licensees with certain tax advantages. For example, the Court affirmed the annual charges of $243,700 and $227,900 using the sharing of the net benefits method for a municipality in "the Vanceburg case," even though the comparable assessed annual charge developed by staff using the same formula for a private entity resulted in $35,050 and $40,400, respectively, for use of the same facility. The proposed rule fails to eliminate the disparity in annual charges between (profit-oriented) investor-owned facilities and (non-profit) municipalities. Furthermore, this disparity, which would be continued using the formula proposed in the NOPR, does not lend support to the claim of "true economic benefits" stated in the preamble to the proposed rule. There are compelling reasons to pass the benefits on to rate payers via a relatively low annual charge regardless of ownership. Since most of the licensees of Federal dam projects are likely to be public utilities, which are by law nonprofit, such licensees will recover only their costs of developing and operating the projects. This situation is unlike that prevailing in the oil and gas industry where a small number of privately-owned energy companies may earn large profits extracting and developing energy resources on Federal lands and therefore requiring compensation to the taxpayers for extraction of non-renewable resources through revenues received by the U.S. Government.

c. The Proposed Method Could Result in a Payment to the Federal Government that Significantly Exceeds the Cost of the Government Dam and Reservoir

The sharing of the net benefits method does compensate the Federal Government for use of the facilities, but the compensation has no relationship to the cost of constructing the Federal facility. In fact, the annual charge for the use of a Federal dam could return to the government charges disproportionate to the share of its cost which would be fairly allocated if the power facility had been constructed originally with the dam. In the extreme case, such a charge when capitalized might exceed the original cost of the dam.

Development of a Federal dam is subject to Congressional authorization, which can only be given if the particular project demonstrates economic viability based on the expected benefits and costs. When a Federal dam is developed for non-hydropower purposes, then the practice is that the economic benefits from the non-hydropower functions must, on a separable basis, justify the cost of construction and operation of the dam and associated facilities. If a non-Federal entity later applies to the FERC for a license to develop hydropower project at the Federal dam, which will require no significant operational changes, the hydropower development would not detract from the other benefits already being derived.

In effect, the hydropower developer merely would be making additional improvements, at his own additional cost and risk. The other beneficiaries of the Federal dam assume no additional financial risk, yet the FERC proposes in its NOPR to give these beneficiaries what appears to be a "windfall profit" in the sense that they are deriving a "shared benefit" from the hydropower addition when they have assumed no capital risk. Taxing the hydropower developer at a rate of 50% of its net profit could unjustly compensate the existing users of the Government dam beyond the hydropower developer's legitimate obligation to share in original cost of constructing the dam. A tax on the developer's profit is clearly the wrong approach.

4. ANALYSIS OF ALTERNATIVE METHODS FOR SETTING ANNUAL CHARGES/NEPA COMPLIANCE

Inequities among applicants and other difficulties with the NOPR leads one to question whether there was not a better alternative method of computation available to FERC staff for analysis and consideration. FERC's interpretation of the Federal Power Act and the sharing of the net benefits method was approved by the Court in City of Vanceburg, KY, vs. FERC 571 F.2d 630 (D.C Cir. 1977), Cert. denied 439 U.S. 818 (1978). The Court approved the sharing of the net benefits method and FERC's case-by-case determination because it met criteria established at Section 10(e) in the Federal Power Act. However, FERC is not restricted to only use a sharing of net benefits method. The Court stated that: "The Commission has discretion within the statute in fixing reasonable annual charges and thus conceivably might use any one of several methods in calculating the charge, actual value of dam use to the specific licensee being one of them." The National Environmental Policy Act (NEPA) and the CEQ regulations implementing NEPA (40 CFR 1500-1508) require that Federal agencies identify, investigate, and disclose to the public all reasonable alternatives to a proposed action. Thus, although the present method (sharing of the net benefits) has judicial approval, the Court directed FERC to explore alternative methods of computing annual charges.

We believe a thorough analysis of alternatives, as required by NEPA, would illustrate that the methods proposed in the NOPR are not the "best" (i.e., equitable, accurate, and efficient) methods available to FERC for the assessment of annual charges. We believe that the NOPR fails to support compliance with NEPA and that further investigation of alternatives is required.

Other alternative annual charge methods are considered in the NOPR (Section VI). Flat rate charges represent the easiest and, if properly applied, most equitable alternative method of assessing annual charges. It is evident from the arguments set forth opposing "A. Flat Rate Charge for Project Energy Produced" and "B. Flat Charge Per Project" that the FERC does not favor this simplified approach to the annual charge determination. The concept of a flat charge per project is dismissed on the grounds that setting a low charge would not provide a reasonable return to the United States; however, no consideration is given to the negative impact of setting a charge which would discourage development of marginally economic projects contrary to Section 10(e) of the Federal Power Act. It follows that FERC must believe the proposed rulemaking would set annual charges somewhere in between an unreasonably low charge and a discouragingly high charge. The question arises as to what is a "reasonable" return, and at what point does the annual charge begin to become a disincentive. Actually, any charge is a disincentive to hydro development, recognizing that in no case can a license be issued free of charge.

Furthermore, the U.S. Congress is presently considering legislation (S.1132) that would establish a flat nominal charge for use of facilities that would not discriminate among classes of applicants and would be simple to administer. The proposed rule fails to document FERC staff investigation of such an alternative as a reasonable means to comply with Section 10(e) of the Federal Power Act.

5. CONCLUSIONS

We believe the Commission's regulations for annual charges should provide an equitable, specific, and easily-applied method of fixing annual charges for the use of Government dams. The sharing-of-the-net-benefits method as proposed by the Commission in the subject NOPR does not meet these criteria.

Based on our analysis of the NOPR we conclude:

a. That a 5-MW cutoff for application of the NOPR is arbitrary and does not correspond to the intent of PURPA.

b. That the proposed method for calculating net project benefits is inaccurate and therefore inequitable.

c. That a 50-50% sharing of net project benefits is not mandated by the Federal Power Act, may result in excessive "windfall" revenues to the Federal Government, and fails to adequately distinguish between municipal and non-municipal licensees.

d. That other means of assessing annual charges (i.e., flat rate charge) would be more equitable and are more easily applied.

e. That the NOPR does not fully analyze all reasonable alternatives, as mandated by NEPA.

f. That the proposed rule would, in fact, have a "significant effect on the human environment".

6. RECOMMENDATIONS

Based on the conclusions listed in Section 5, and our analysis of the NOPR, we recommend that:

a. FERC conduct a comprehensive assessment of alternatives to the NOPR which examines the comparative equity of each alternative and evaluates the effects of each alternative method on municipal and non-municipal licensees.

b. FERC carefully consider a flat charge based on dependable capacity and actual annual generation such as that being considered by the U.S. Congress (S.1132).

c. FERC apply only a nominal charge to projects with installed capacities of 30 MW or less.

d. If a sharing-of-the-net-benefits approach continues to be considered, the value of project power be system-based and project-specific, not regional and generalized.

In conclusion, we recommend that FERC adopt a constant nominal charge such as that proposed by Congress ($1.00 per kW of installed capacity and 1/2 mil/kWh of annual energy generation). This flat charge coupled with reimbursement to the government of actual operation and maintenance costs for use of the Federal facility would be the most equitable and easily applied method of assessing annual charges. This approach appears to meet the Vanceburg criteria in that the Government would be compensated by the licensee at a level proportional to the benefit received, while encouraging development of this valuable renewable resource. Use of the constant nominal charge will address the goals of equity and simplicity and will impose the least practicable regulatory burden on the Applicant's and FERC's staff.

Glasgow Irrigation District P.O. Box R Malta, Montana 59538
Phone 654-1440

July 13, 1983

Mr. Howard Useem
Senate Energy & Natural Resources Committee
Dirksen Senate Office Building
Washington D. C. 20510

Dear Mr. Useem and Committee Members:

We wish to go on record as being in support of Senate Bill #1132 on the falling water charge and request passage of this legislation.

The present rates proposed by the Department of Interior and Bureau of Reclamation for annual charges for use of Government Dams are excessive, and would discourage participation by non-Federal interests in development of Hydro Power.

We feel that passage of Senate Bill #1132 would help stabilize further hydro power development.

Sincerely yours,

GLASGOW IRRIGATION DISTRICT

Sever Enkerud
President F.S.

JUL 2 [illegible] 1983

Kings River Conservation District
4886 E. Jensen Avenue • Fresno, California 93725
Telephone: (209) 237-5567

File: 512.04

July 19, 1983

Senator McClure, Chairman
Energy and Natural Resources Committee
The United States Senate
Washington, D.C. 20510

Dear Senator McClure:

The Kings River Conservation District would like to express its strong support of S.1132 that would amend Section 10(e) of the Federal Power Act by setting a limit on the annual charge that can be assessed by the Federal Energy Regulatory Commission for use of a government dam by a non-federal licensee.

The Kings River Conservation District (KRCD) is the licensee of a hydroelectric plant at the existing Corps of Engineers' Pine Flat Dam located approximately 25 miles east of the City of Fresno, California. This project was licensed by the FERC on September 25, 1979 and construction of the project is due to be completed by the end of this year. The project has a total installed capacity of 165,000 kW and will have an average annual output of 420 million kWh.

Under the terms of a power sale contract between the KRCD and the California Department of Water Resources (CDWR) the power from this project will be used by CDWR in the operation of the State Water Project.

When the license for this project was issued, the FERC deferred setting the annual charge pending a rulemaking to establish the procedures for setting such a charge. That rulemaking was issued on March 31, 1983. The KRCD submits that the proposed annual charges rule is inequitable in application, will not result in the assessment of a reasonable annual charge and is therefore contrary to the requirements of Part I of the Federal Power Act, as amended. The proposed rule is irremediably flawed for the further reasons that it fails to adequately explain or justify the numerous legal and economic assumptions which form the basis for the proposed methodology and fails to provide much of the information needed to enable those parties who will be directly affected by the rule to assess, with any assuredness, the proposed rule's impact.

Division I, NORMAN B. WALDNER, Dinuba • Division II, MASARU YOSHIMOTO, Fowler
Division III, RAYMOND W. LAMBRECHT, Kerman • Division IV, GEORGE D. McKEAN, Riverdale
Division V, HUGH V. JOHNS, Hanford • Division VI, EDWIN H. HOWE, Stratford
At Large, GARVIN H. WHITE, Fresno

GARVIN H. WHITE, President • GEORGE D. McKEAN, Vice President
JEFF L. TAYLOR, General Manager-Chief Engineer, Secretary
RAY F. TEDDER, Auditor Controller • WILLIAM F. DOCKER, Attorney-At-Law

Senator McClure, Chairman
Energy and Natural Resources Committee
The United States Senate
Page 2

Accordingly, the KRCD supports a flat rate annual charge of $1 per kilowatt of installed capacity and 1/2 mill per kilowatt-hour of energy produced. The KRCD believes that such a flat rate charge is consistent with Section 10(e) requirements, readily calculable, simple to administer and strikes a fair balance between the often competing objectives of encouraging hydro-power development. It will provide a reasonable return to the United States for the benefit conferred upon a licensee by its use of a Government dam and insuring that the annual charge assessed does not result in an unwarranted increase in the cost of power to consumers. A simplified annual charges approach which results in a predictable yet reasonable charge is essential to encourage the use of existing public investments for developing renewable resources in a manner consistent with the national interest in energy conservation and energy independence.

Sincerely yours,

Jeff L. Taylor
General Manager-Chief Engineer

JLT/ls

cc: Senator Wilson
Senator Cranston
Congressman Pashayan
Congressman Lehman
Congressman Coelho
R.G. Ferreira, DWR
C.D. Williams

Malta Irrigation District P.O. Box R Malta, Montana 59538
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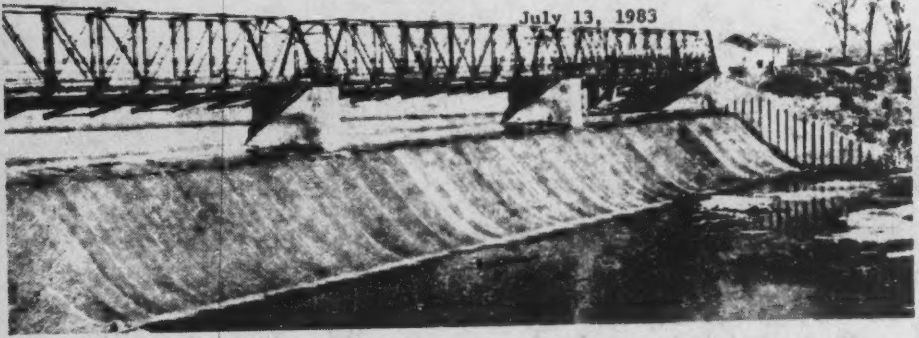

July 13, 1983

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Senate Energy & Natural Resources Committee
Dirksen Senate Office Building
Washington D. C. 20510

Dear Mr. Useem and Committee Members:

We wish to go on record as being in support of Senate Bill #1132 on the falling water charge and request passage of this legislation.

The present rates proposed by the Department of Interior and Bureau of Reclamation for annual charges for use of Government Dams are excessive, and would discourage participation by non-Federal interests in development of Hydro power.

We feel that passage of Senate Bill #1132 would help stabilize further hydro power development.

Sincerely yours,

MALTA IRRIGATION DISTRICT

Ted Ereaux
President F.S.

Official Committee File

Mid-West Electric Consumers Association, Inc.

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LOW COST POWER FOR EVERYONE

July 18, 1983

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
JUL 18 1983
WASHINGTON, D.C. 20510

Honorable James A. McClure
Chairman
Committee on Energy and
Natural Resources
United States Senate
Washington, D.C.

Dear Senator McClure:

I am writing this letter on behalf of Mid-West Electric Consumers, Inc. ("Mid-West") to comment on S. 1132, which specifies annual charges for hydroelectric projects with licenses issued by the Federal Energy Regulatory Commission ("FERC") for the use of Federal dams and other structures. Mid-West requests that this letter be made part of the hearing record in the Committee's consideration of that bill.

Mid-West, formed in 1958, is a South Dakota non-profit membership corporation headquartered in Evergreen, Colorado. It is the regional service agency of over 300 rural electric cooperatives and consumer-owned electric utilities serving over 3,000,000 consumers in the nine states comprising the Missouri basin: Colorado, Wyoming, Montana, North Dakota, South Dakota, Nebraska, Kansas, Iowa, and Minnesota. These states contain numerous Federal dams which have been and others which could be developed for hydroelectric power. Mid-West members, as potential developers of such hydroelectric projects, are vitally concerned that charges for developing the projects be fair and not excessive. Additionally, Mid-West members, as beneficiaries of other features of Federal dams, such as irrigation and flood control, are equally concerned that the Federal Government receive adequate reimbursement for the use of such facilities in the private development of hydroelectric power.

The FERC has proposed amendments to its regulations regarding fees to be charged for hydroelectric projects affiliated with Federal dams. Mid-West strongly opposes those regulations as imposing excessive fees and as a departure from traditional cost-of-service principles used in setting rates. S. 1132 would place a ceiling on such fees. However, S. 1132 also departs from cost-of-service principles. Mid-West would urge this Committee, as it has urged the Federal Energy Regulatory Commission, to fashion fees based upon the Federal investment in a dam, in accordance with cost-of-service ratemaking.

Problems Inherent in the Proposed Rulemaking

In recent years, the FERC has computed the charges for use of Government dams for hydroelectric projects on an individual basis, normally using the "sharing of the net benefits" formula, pursuant to which the FERC computes the cost of the least expensive alternative sources of power, subtracts the annual cost of power from the plant being constructed, and requires payment of the difference between the two costs.

Now, the FERC plans to use a detailed methodology, based on the regional, rather than the individual, value of power. The proposed rulemaking contemplates a "sharing of the net benefits" generic formula, based upon regional power values, with an annual increase based on inflation.

There are a number of problems inherent in the proposed rulemaking. Mid-West wishes to discuss here four of the more blatant problems which result in exaggerated fees for hydroelectric projects affiliated with Federal dams.

First, the proposed rulemaking uses regional power values and calculates the net benefits as "the difference between the appropriate regional power value and the estimated project power costs." 48 Fed. Reg. 15134, 15135 (April 7, 1983). The proposed rulemaking states that the regions will be selected "based upon similarity of alternative power generation costs and projected regional fuel costs" and anticipates selection of 18-20 regions in the final rule. 48 Fed. Reg. at 15137.

However, in actuality, some utilities in a region will have alternative power costs greater and some less than the regional power values developed pursuant to the generic rule. Those systems with alternative power costs greater than the regional average would be paying less than their aliquot share to the Government based on the rulemaking formula. Those systems with alternative power costs lower than the regional average may be inhibited from hydroelectric development because of the disproportionate amount of fees required in order to undertake such development at Federal dams.

With a general policy encouraging hydroelectric development, and a policy which should encourage full use of multipurpose dams, including hydroelectric development, it is counterproductive to charge fees which would result in discouraging such development.

Second, the proposed rulemaking assumes that it is appropriate to measure net benefits from development of a hydroelectric project at a Government dam by comparing an alternative thermal generating unit. However, in an area with a large amount of excess capacity, wholesale purchases might be the next least expensive alternative to constructing a hydroelectric project at a Federal dam. In other locations, the construction of another hydroelectric project could be the least expensive alternative.

In fact, if a rulemaking appropriately measured benefits by an alternative source of power, the only appropriate measure would be a hydroelectric project not associated with a Federal dam. In passing § 10(e) of the Federal Power Act, 16 U.S.C. § 803(e), Congress differentiated between hydroelectric projects constructed at a Federal dam and hydroelectric projects not affiliated with a Federal dam. See City of Vanceburg, Kentucky

v. Federal Energy Regulatory Commission, 571 F.2d 630, 644-45 (D.C. Cir. 1977). Municipalities and states which resell power without profit are exempt from fees unless they are constructing a project affiliated with a Federal dam. In debating § 10(e), the Senate thought it appropriate to charge no fees in the case of any hydroelectric project not affiliated with a Federal dam. See Vanceburg, 571 F.2d at 645-46. The reason for the differentiation was the belief that the Federal dam conferred a benefit on a licensee which would not be conferred if the licensee built its own dam. Id. This benefit would appropriately be measured by the difference between the cost of a hydroelectric project not affiliated with a Federal dam and a hydroelectric project affiliated with a Federal dam. As finally adopted, § 10(e) required fees, except for certain states and municipalities, for hydroelectric projects not affiliated with Federal dams. However, the final Act retained a distinction between the two types of projects by requiring all entitites, including all states and municipalities, to pay fees for projects affiliated with Federal dams.

Third, the proposed rulemaking plans to levelize both the project values and the project power costs. 48 Fed. Reg. at 15135. Cost of construction would be levelized based on the present value of money. Cost of fuel would be levelized based upon anticipated increases in the cost of fuel. Because hydroelectric projects subject to the rulemaking have no cost of fuel, this levelization would substantially increase the differential between the cost of thermal power and the cost of hydroelectric power.

The proposed rulemaking illustrates the potential impact of the use of a levelized fuel cost. In Wyoming, the proposed rulemaking anticipates that the cost of fuel would increase 13.87% from July 1982 to July 1985 and .58% from July 1990 to July 1992. As a result, the proposed rulemaking uses, as an example, a fuel cost multiplier of 1.47% to be applied during the first ten years of the project. 48 Fed. Reg. at 15142. In the example, the alternative thermal plant would pay 77.4 cents per million Btu the first year of operation. However, the hydroelectric developer would split benefits based upon a levelized fuel cost of 113.8 cents per million Btu. Id. Thus, in the early years, the developer would pay substantially more than half the difference between the cost of a hydroelectric development and the cost of an alternative thermal unit.

Fourth, the proposed rulemaking would increase the annual use charge based upon inflation. 48 Fed. Reg. at 15135. Use of the GNP Deflator to increase annual payments runs afoul of § 10(e) of the Federal Power Act which allows this Commission to increase annual charges only after the first twenty years, and then every ten years thereafter upon notice and opportunity for hearing. The proposed rulemaking would increase those charges annually.

The proposed rulemaking first inflates the net benefits by using levelized costs and then adds an inflation ratio to the net benefits. In this way, the proposed formula maximizes the user charges and, thereby, maximizes potential consumer rate increases.

Section 10(e) of the Federal Power Act directs the FERC, in setting charges, to "seek to avoid increasing the price to the consumers of power by such charges..." By maximizing its charges, the FERC would maximize the potential of increased consumer rates, contrary to its statutory directive.

Proposed Calculation of Charges

Mid-West proposes that charges for construction of hydroelectric facilities at Government dams be based upon the specific dam and the cost to the Government of such dam. Specifically, Mid-West would propose that the developer pay a proportionate cost of the existing Government dam. A similar cost allocation is made for the power portion of existing Government dams when the hydroelectric power is developed by the Federal Government.

Pursuant to § 10(e) of the Federal Power Act the FERC has certain directives as to the license fees. The purpose of such fees is listed as (1) reimbursing the United States for the cost of administration of hydroelectric licensing; (2) recompensing the United States "for the use, occupancy, and enjoyment of its lands or other property"; and (3) the expropriation of excess profits. The second objective relates directly to fees for developing hydroelectric projects in connection with Government dams.

Traditionally, the FERC has followed a cost of service ratemaking methodology. See e.g., Lockhart Power Co., Op. No. 29, 4 FERC ¶ 61,337, 61,799-800 (1978). A utility may only earn a return on the investment it has made. That utility may not earn a greater or lesser return based on the cost of alternative power supply. Here, the United States should not be allowed to earn a return disproportionate to its investment in the dam.

This theory is followed in Federal development of hydroelectric facilities in connection with multipurpose water development. The hydroelectric facility is allocated a portion of the joint cost of the dam and reservoir, and hydroelectric power consumers repay that cost, as well as the costs of the hydroelectric plant itself, in their electric rates. In addition, if water users are unable to pay fully the irrigation costs, hydroelectric rate payers would contribute to meeting such costs.

In a similar fashion, the FERC could set fees based upon an allocated portion of the cost of the Federal dam and reservoir. By so doing, this Commission would follow the statutory purpose in § 10(e) of the Federal Power Act of "recompensing [the United States] for the use, occupancy, and enjoyment of its lands or other property." The compensation would have a direct nexus to the Federal dam affiliated with the hydroelectric project by subsidizing the other uses of the Federal dam and thereby reducing the cost of the Federal dam to the taxpayer. Where the reservoir makes only a nominal contribution to power, the fee for use of the dam should likewise be nominal because no benefit is in fact being conferred.

This purpose could be accomplished by amending § 10(e) of the Federal Power Act by modifying the last clause of the sentence preceeding the last sentence to read as follows: "but in no case shall a license be issued free of charge for the development and utiiization of power created by any Government dam, and the amount of such charge shall be based upon the portion of the cost of the dam and reservoir which can properly be allocated to power and, where the dam involved is an element of a project governed by the Federal Reclamation laws (Act of June 17, 1902, 32 Stat. 388, and all Acts amendatory thereof and supplemental thereto), the provision of repayment assistance to irrigation to the same extent as would be the case were the licensed project developed by the United States under such laws."

In this way, the calculation of fees for non-Federal hydroelectric development in affiliation with Government dams would be consistent with the calculation with such fees for Federal hydroelectric development at such dams. Additionally, it would be consistent with traditional cost-based ratemaking.

Mid-West urges the Committee to amend S. 1132 as above proposed so that the FERC would be required to establish fees for hydroelectric projects affiliated with Government dams based on the cost of the Government dam and reservoir properly attributable to power, including where the dam in question is a part of a Federal reclamation project, assistance in repaying irrigation costs to the same extent as would be the case were the power development to be undertaken by the United States.

Sincerely,

Fred G. Simonton

Fred G. Simonton
Executive Director

MILK RIVER IRRIGATION DISTRICTS

Box R Malta, Montana 59538 Phone 654-1440

July 13, 1983

Mr. Howard Useem
Senate Energy & Natural Resources Committee
Dirksen Senate Office Building
Washington D. C. 20510

Dear Mr. Useem and Committee Members:

We wish to go on record as being in support of Senate Bill #1132 on the falling water charge and request passage of this legislation.

The present rates proposed by the Department of Interior and Bureau of Reclamation for annual charges for use of Government Dams are excessive, and would discourage participation by non-Federal interests in development of Hydro power.

We feel that passage of Senate Bill #1132 would help stabilize further hydro power development.

Sincerely yours,

MILK RIVER IRRIGATION DISTRICTS

Lever Enkerud
President

Malta Irrigation District
Box R
Malta, Montana 59538

Glasgow Irrigation District
Box R
Malta, Montana 59538

Dodson Irrigation District
Box R
Malta, Montana 59538

Paradise Valley Irrigation District
Box 827
Chinook, Montana 59523

Alfalfa Valley Irrigation District
84 Third Street
Chinook, Montana 59523

Zurich Irrigation District
36 Indiana
Chinook, Montana 59523

Fort Belknap Irrigation District
Chinook, Montana 59523

Harlem Irrigation District
Harlem, Montana 59526

JUL 28 1983

MID MODESTO IRRIGATION DISTRICT

1231 eleventh street • p.o. box 4060 • modesto, california 95352 • phone (209) 578-1[illegible]

July 25, 1983

The Honorable James McClure
United States Senate
Washington, DC 20510

Subject: Federal Annual Dam Use Charges for Hydroelectric Projects

Dear Senator McClure:

Section 10 (e) of the Federal Power Act provides for the Federal Energy Regulatory Commission (FERC) to assess a charge for the use of federal dams by non federal entities for the purpose of hydroloelectric project development and operation. FERC is to set such charges in licenses issued by the FERC for projects to be developed at existing federal dams. The FERC issued a proposed rulemaking on this subject in March 1983. The proposed rulemaking would establish a charge which the FERC estimates to be 50 percent of the net benefits available from the project.

Applicants or licensees for the development of the small hydroelectric projects at existing federal dams, canals, and other such water projects have been faced with the uncertainty of what the FERC would establish as federal dam use charges. The Modesto Irrigation District is currently undertaking final design of a 2.5 MW project at an existing U.S. Army Corps of Engineers Dam in Calaveras County, California, and is interested in developing similar projects at other federal dams. To date, the District has received no indication from the FERC as to what fees might be imposed for the use of the federal dams. Along with the District are numerous other water and irrigation districts, utilities, cities, other public entities, and private developers throughout the country who have expended substantial sums to study and develop hydroelectric projects at existing federal dams. The District is concerned that under the proposed rulemaking the FERC will significantly reduce or eliminate the incentive to develop small hydroelectric projects at federal dams.

Senate Bill 1132 was introduced in recognition of this problem. This bill would establish a charge of $1 per kilowatt of installed electrical capacity and $.0005 per kilowatthour of energy generated per year for projects which use federal dams. This formula would establish a charge which small hydroelectric projects at federal dams could economically support.

On July 25, the Senate Committee on Energy and Natural Resources held an open hearing on Senate Bill 1132 which would establish a reasonable limit on any fees to be applied by the FERC. It is our understanding that the record will be held open for two weeks following this hearing for any written comments. We request your support for Senate Bill 1132 in order to keep the FERC from establishing federal dam charges fees which could reduce the extent of development of this important renewable energy resource.

Sincerely,

Mathew Fiscalini

Mathew Fiscalini, President
Board of Directors

DEPARTMENT OF NATURAL RESOURCES
AND CONSERVATION
WATER RESOURCES DIVISION

TED SCHWINDEN, GOVERNOR
32 SOUTH EWING
STATE OF MONTANA
(406) 449-2872 ADMINISTRATOR
(406) 449-2864 ENGINEERING BUREAU
(406) 449-3760 WATER DEVELOPMENT BUREAU
(406) 449-2872 WATER MANAGEMENT BUREAU
(406) 449-3962 WATER RIGHTS BUREAU
HELENA, MONTANA 59620

July 21, 1983

Honorable James A. McClure, Chairman
Senate Committee on Energy and Natural Resources
SD-360
Washington, D.C. 20510

Dear Senator McClure:

On behalf of the Montana Department of Natural Resources and Conservation, enclosed please find testimony in response to Senate Bill 1132. I thank you for this opportunity to submit these comments for consideration at the scheduled July 25, 1983 hearing.

Sincerely,

Gary Fritz

Gary Fritz
Administrator

Enclosure

TESTIMONY ON SENATE BILL 1132

SUBMITTED BY

GARY FRITZ, ADMINISTRATOR
WATER RESOURCES DIVISION
MONTANA DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION

TO THE

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C.

FOR COMMITTEE HEARINGS TO BE HELD ON JULY 25, 1983

Testimony on Senate Bill 1132

July 25, 1983

Submitted by the Montana Department of
Natural Resources and Conservation

The following comments focus on concerns this Department has with Senate Bill 1132, as well as with other related Federal Energy Regulatory Commission (Commission) activities that we feel should be brought to the attention of the Senate Committee on Energy and Natural Resources.

Senate Bill 1132

Senate Bill 1132 attempts to clarify the federal role in hydropower fee assessment at federal dams. According to testimony by Senator McClure (Senate Congressional Record; April 21, 1983), singling out the Commission as the sole assessor of a standardized fee will help the private developer to estimate project feasibility more accurately prior to licensure. However, we think this approach may overlook the importance of the Bureau of Reclamation's (Bureau) role authorized under the 1939 Reclamation Act in assessing annual use fees at its projects.

With the passage of Senate Bill 1132, Montana's obvious concern is that falling water charges assessed by the Bureau will no longer be available for circulation back into the Pick-Sloan Program water development projects authorized under the 1944 Flood Control Act. Without these revenues, the Bureau's ability to maintain the original pruposes of its projects may be limited significantly. Therefore, we urge that the Senate Committee on Energy and Natural Resources (Committee) give special attention to the effects of Senate Bill 1132 on important Bureau operations and on future water users. We feel that the use of fees if assessed by the Commission is not at all clear, and we recommend that the benefits of the Bureau's established and workable assessment procedure should not be overlooked.

Proposed Commission Rules

Directly related to Senate Bill 1132 are the Commission's proposed rules entitled "Annual Charges for Use of Government Dams and Other Structures Under Part 1 of the Federal Power Act" (Federal Register; April 7, 1983). Although rulemaking by the Commission is authorized under the Federal Power Act, we again question the role which the Commission would assume over current Bureau responsibilities.

The proposed methodology is deficient in several areas. The methodology provides for a sharing of the "net benefits" of a project between the government and a developer. This net benefit is the difference between the value of power produced and the actual costs associated with producing it. The methodology proposes to calculate the value of power on the basis of generic avoided cost, not on actual estimates of revenues. This use of avoided cost may have a significant effect on the development of government dams. It will in effect put the developer into the position of being squeezed between the utilities, who are arguing for the lowest possible rates for purchase under the avoided cost provisions of the Public Utilities Regulatory Policy Act, and the Commission, which proposes a method that results in the highest estimate of avoided cost. Therefore, the Commission has proposed the use of a high avoided cost estimate that will overstate actual net benefits of a project.

The Commission's methodology also claims that the avoided cost is to be calculated using the least cost alternative. It appears, however, that the Commission assumes the least cost alternative to be a steam plant, which may overstate the avoided cost. Further, the proposed methodology does not account for prolonged periods when no generation is constructed. It can not distinguish between regions which are growing rapidly and those in which growth has slowed. In the former case, there will be more or less a continuous stream of plans coming on line, and the proposed methodology may be reasonable. In the latter case, no additional plans may be needed for a substantial amount of time. Since this methodology does not account for long time lags before benefits show up, the value of the benefits will be overstated.

The designation of regional boundaries may also turn out to be a problem for Montana even if the Commission revised its proposed methodology to account for the difficulties raised here. The Commission expects that 18 to 20 regions will be identified in the final rule, and that the selection of regions will be based on "similarity of alternative power generation costs and projects regional fuel costs." These criteria lead one to believe that Montana would be a region with Wyoming, and possibly Utah, based on an assumption that mine mouth coal plants would be the rule. The assumption would ignore Montana's tie to the Northwest based on existing utility planning arrangements. The criteria for defining regional boundaries should be expanded to include actual utility planning situations.

These points regarding the proposed rules were detailed in formal comments from this State to the Commission. However, I mention them here to point out that fee assessment by the Commission, although statutorily authorized, may be inappropriate.

Other Concerns

At this time when Senate Bill 1132 is under consideration, I should touch upon a number of difficulties and issues that are evident at the state level as the Commission proceeds in carrying out its hydropower authorization mandate. These issues, as outlined in a recent correspondence to Commission Secretary Plumb from Governor Schwinden, are raised only to point out that the role of the Commission is misunderstood in light of other current state and federal agency mandated activities.

Briefly stated, the number of hydropower development projects proposed in Montana has increased dramatically, and many of these lack for adequate planning. The Commission's revised licensing and exemption procedures have afforded some state agencies an opportunity to participate in the analysis of these proposals. However, recent proliferations of projects has placed a marked burden on available staff and funds at the state level. Aggravating the situation is the lack of available streamflow and fishery information at most small hydropower sites. These circumstances have resulted in earnest but abbreviated efforts by our agency staff to submit technical comments to the Commission within short comment deadlines. In essence, the states need more time to complete a thorough site-specific analysis and to satisfy all state regulatory requirements (e.g. water rights). It does not appear that the Commission has available staff time to make this same kind of localized environmental analysis and engineering review. We feel, therefore, that state water management agency concerns and recommendations should be made as integral and mandatory components of the Commission's decision-making procedures. Short comment deadlines and lack of collaboration do not currently espouse this need.

One final area which needs clarification involves the federal stipulation of bypass or release flows at diversion or dam sites. Although the flows may have been recommended by state agencies, the legal status of these allocations has not been defined in any federal policy. The State of Montana is currently in the process of developing a state policy on this issue and feels it is appropriate to initiate discussions on how the federally stipulated instream flows which accompany certain authorizations can best be managed within Montana's water rights appropriation system.

Summary

In direct response to Senate Bill 1132, we do not feel that the Commission should assume the role of fee assessor at all federal dams until possible conflicts in rulemaking authority between the Bureau and the Commission are resolved. We also wish to bring to your attention other issues which do not lead us to support Senate Bill 1132 at this time. These issues include possible inconsistencies in the Commission's proposed rules, and questions regarding the lack of coordination of federal hydropower licensing activities with state water management responsibilities. Thank you for this opportunity to submit comments.

Official Committee File

NATIONAL WILDLIFE FEDERATION
1412 Sixteenth Street, N.W., Washington, D.C. 20036 202—797-6800

July 25, 1983

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
JUL 27 1983
WASHINGTON, D.C. 20510

The Honorable James A. McClure
Chairman
Committee on Energy & Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

Please accept this letter for the record of the Committee on Energy & Natural Resources on S. 1132, your bill to amend the Federal Power Act. S. 1132 would limit the amount of the annual charges for hydropower licenses issued by the Federal Energy Regulatory Commission (FERC), and would preclude the Bureau of Reclamation from seeking any cost recovery from non-Federal hydropower developers. The National Wildlife Federation is opposed to enactment of the bill.

Upon introducing the legislation earlier this year, you stated that this bill "will go far toward clarifying the seeming uncertainties which surround the development of hydroelectric facilities at Government dams by non-Federal entities." However, a recent rulemaking proposed by the FERC on April 7 (48 FR 15134) will, in our judgement, clarify the uncertainties and eliminate the need for passage of the bill.

One of the problems that the bill is intended to remedy is the uncertainty concerning the amount of the Federal "falling water" charge to potential non-Federal hydropower investors. Such developers would benefit from a fixed formula to follow to estimate in advance the annual charges that the Government would levy. You noted that knowledge of the annual charge in advance would be particularly valuable to the small developer who may be unable to afford the consulting service that would be necessary in order to estimate what the annual charge would be, given the complex system of rate computations possible under existing law.

48th ANNUAL MEETING MARCH 15-18, 1984 Omni International Hotel, Atlanta, Georgia
100% reclaimed paper

Under FERC's proposed rule, the complex system of individual rate computations would no longer be performed. The Commission intends to replace the present case-by-case calculations under 18 CFR 11.22 with a generic formula-based approach. FERC will calculate the value of hydropower for 18 regions of the nation. This proposal will reduce the time and resources now required to assess annual charges.

S. 1132 would limit the annual charge to $1 per kilowatt of installed capacity and one-half mil (1/20 of a cent) per kilowatt of energy generated and would eliminate any other charges by the Bureau of Reclamation for use of reclamation works for power production. These limits are intended to eliminate uncertainties but the FERC proposed charges will end these uncertainties. FERC's falling water charge will not inhibit hydropower development because the 50-50 split between the Government and the developer is calculated on the excess profit (economic rent) that is available after the developer has amortized his or her costs and earned a reasonable profit.

If a site has a high head and volume of water and is very profitable, the FERC would levy a high falling water charge based on the 50-50 formula, but the developer will still be able to earn a greater than normal profit. Conversely, the charges for marginal hydropower sites will be minimal ($100 per year).

There is a misconception concerning payments to the Bureau of Reclamation. Payments by non-Federal licensees at dams owned by the Bureau of Reclamation are not designed to capture the economic value of power produced at a dam. These are designed to recover part of the costs of the dam. This is consistent with current repayment policies for Federal water resource investment, and in our judgement should not be precluded by the enactment of S. 1132. Of course, the Federal Energy Regulatory Commission should include the costs of a developer's payments to the Bureau for the use of the dam in calculating the net benefits upon which the FERC annual charges are based.

It is not clear from the language of S. 1132 whether the "actual unreimbursed cost to the United States, if any, resulting from the construction, operation, and maintenance of the licensee's project works" will fully subsume a cost allocation to hydropower that might otherwise be performed by the Bureau of Reclamation. Additionally, the ceiling placed on the annual charge by the bill will yield considerably less revenue than the annual charge formula proposed by the FERC. Thus, S. 1132 would unnecessarily reduce payments to the Treasury for the private use of public water resources and Federally financed dams and related facilities. For this reason, the Federation is opposed to enactment of the bill.

Sincerely,

E. R. Osann

Edward R. Osann, Director
NWF Water Resources Program

cc: The Honorable J. Bennett Johnston

ELECTRIC DEPARTMENT
5TH & MAIN STREETS, P. O. BOX 159
NORTH LITTLE ROCK, ARKANSAS 72115
PHONE (501) 372-0100

Official Committee File

July 11, 1983

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
JUL 15 1983
WASHINGTON, D.C. 20510

The Honorable James A. McClure
Chairman
Senate Committee on Energy and
Natural Resources
SD-360 Dirksen Senate Office Building
Washington, D.C. 20510

Attn: Howard Useem

Re: Senate Energy Committee Hearing on
S. 1132, annual charge legislation

Dear Senator McClure:

In the very near future, we are expecting to be awarded a license to build a hydro facility at the Murray Lock and Dam in the Little Rock/North Little Rock, Arkansas area. We, therefore, have an interest in the outcome of the above-referenced hearing and are submitting the attached statement to the Senate Committee on Energy and Natural Resources for their inclusion in the hearing record on S. 1132.

We appreciate your consideration of our statement in support of S. 1132 as its passage and the subsequent establishment of a fair and reasonable limit on the annual fees to be assessed our project could be vital in helping to ensure that it remains economically feasible.

Yours very truly,

R. E. Hogan

R. E. Hogan
General Manager

REH:lwl

Enc.

cc w/enc.: Mayor Thompson
City Hall, NLR, AR

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

HEARING ON S. 1132

STATEMENT OF ROBERT E. HOGAN, GENERAL MANAGER, NORTH LITTLE ROCK ELECTRIC DEPARTMENT, NORTH LITTLE ROCK, ARKANSAS ON BEHALF OF THE CITY OF NORTH LITTLE ROCK, ARKANSAS

North Little Rock Electric Department is a municipally owned electric system that has been in business since 1907 serving the citizens of North Little Rock and, since 1940, customers outside the City limits residing in a service area certified to us by the Arkansas Public Service Commission. The system now serves thirty thousand customers. At present, North Little Rock Electric Department is a wholesale full requirements customer of Arkansas Power and Light Co. under an agreement which will expire in 1986. Therefore, hydro generation is a real alternative for the City of North Little Rock. The customers of NLRED now require a peak supply of 160 MW with annual energy requirements of 550 million KWH. Except for a few hours per year, the full requirements of the proposed hydro station at nearby Murray Lock and Dam on the Arkansas River could be fully utilized by the NRLED system.

The City of North Little Rock received its preliminary permit for this project on March 1, 1981 and, with the current economic conditions being conducive to the likely response by several competent and responsible bidders, looks forward in the very near future to being awarded a license to build a hydro facility at the Murray Lock and Dam, a federal government owned facility operated by the Corps of Engineers.

On March 31, 1983, the Federal Energy Regulatory Commission issued a notice of proposed rulemaking regarding annual charges for the use of government dams and other structures. Section 10 of the Federal Power Act required that annual fees shall be assessed licensees for projects which develop and utilize power created by any government dam. The Commission has been determining such charges on a case-by-case basis. Its new rule is intended to provide a generic approach to this question. (The rule was published in the Federal Register on April 7, 1983, pages 15134 - 15153.)

In essence, the rule would require a "sharing of the net benefits" between the federal government and the developer. The actual cost of the project would be subtracted from the next least costly alternative source of power, determined on a regional rather than utility-specified basis.

The developer would pay to the government one-half of difference. Fees assessed under this formula would be significant. In many cases they might make a marginal project uneconomical.

Our position in opposition to the generic formula is as follows:

1. In fairness, the annual payment to the government for the use of its land for a retrofit hydro facility should not exceed what the federal government would likely receive were it to complete the project with federal funds and market the power through one of the regional marketing agencies of the Department of the Interior, i.e., there should be no windfall profits to the federal government occasioned by non-federal development. In our instance, the net income for our project at Murray Lock and Dam should not exceed the net income which could be realized by the Southwestern Power Administration which is the marketing agent of federally produced hydro power in our region.
2. S. 1132 would limit annual charges to $1 per installed KW and 1/2 mill per KWH. For our project, this works out to be on a per KWH basis nearly equal to the net income per KWH received by SWPA for each KWH distributed in 1982. The bill would also require the developer to repay the federal government for any unreimbursed federal expenditures incurred as a result of the development; to which we are amenable.

We strongly urge your support of S. 1132.

JUL 2 8 1983

CITY OF REDDING
CALIFORNIA

July 25, 1983

The Honorable James McClure
United States Senate
Washington, DC 20510

Subject: Federal Annual Dam Use Charges for Hydroelectric Projects

Dear Senator McClure:

Section 10(e) of the Federal Power Act provides for the Federal Energy Regulatory Commission (FERC) to levy a charge for the use of federal dams by non federal entities for the purpose of hydroelectric project development and operation. Such charges are to be set in licenses issued by the FERC for projects to be developed at existing federal dams. The FERC issued a proposed rulemaking on this subject in March 1983. The proposed rulemaking would establish a charge which the FERC estimates to be 50 percent of the net benefits available from the project. The City of Redding is concerned that this proposed rule will seriously affect the economics of many proposed small hydroelectric projects at existing dams.

Parties interested in developing small hydroelectric projects at existing federal dams, canals, and other such water projects have faced continued uncertainty of what the FERC would establish as federal dam use charges. The City of Redding has been in various stages of evaluation and development of four hydroelectric projects at federal dams and diversions in California for several years with no indication from the FERC as to what charges might be imposed for the use of the federal facilities. Redding, as with other numerous municipal utilities, water and irrigation districts, cities, and other entities throughout the country have expended substantial sums to study and develop hydroelectric projects at existing federal facilities. With the release of the FERC's recent proposed rulemaking on this issue, the City is deeply concerned that the FERC will significantly reduce or eliminate the incentive to develop small hydroelectric projects at federal facilities.

In recognition of this problem, Senate Bill 1132 would establish a fee of $1 per kilowatt of installed electrical capacity and $.0005 per kilowatthour of energy generated per year for projects which use federal dams. This formula would

760 PARKVIEW AVENUE-REDDING CA 96001 - TEL 916-246-1151

establish a significant fee which the majority of small hydroelectric projects at federal facilities could support economically.

On July 25, the Senate Committee on Energy and Natural Resources held an open hearing on Senate Bill 1132 which would establish a reasonable limit on any fees to be applied by the FERC. It is our understanding that the record will be held open for two weeks following this hearing for any written comments. We request your support for Senate Bill 1132 in order to keep the FERC from establishing charges for the use of federal facilities for small hydroelectric projects which could seriously impact the development of such projects.

Sincerely,

Barbara Allen Gard

Barbara Allen Gard
Mayor

"SERVING 72,000 ACRES IN THE YAKIMA VALLEY"

Roza Irrigation District

CORNER OF 13th STREET and BLAINE AVENUE • P. O. BOX 810 • SUNNYSIDE, WASHINGTON 98944 • PHONE 837-5141

July 19, 1983

Senator James McClure
Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator:

Thank you for sponsoring S1132, to limit the charges FERC can levy on hydro power development. We believe this is a big step in the right direction.

However, consideration has not been given to the fact that many dams to which the government holds title, actually are being, or have been paid for in total by an irrigation district. Also, full cost of annual O & M is paid for by the same entity.

Therefore, we request that you amend your bill to include two more aspects that would correct this situation.

(1.) When the hydro power developer is the same entity as the original project sponsor, all FERC charges should be waived.

(2.) When the hydro power developer is not the original project sponsor, a percentage of the FERC charges should be credited back to cover a portion of the annual O & M costs of that facility.

If you would make these two amendments you would have full support for its passage from irrigation districts.

Thank you for your consideration.

Yours truly,

Ron Van Gundy
Manager

RVG:mm

JUL 2 5 1983

DIVISIONS
Light
Water
Belt Line

City of Tacoma
WASHINGTON

DEPARTMENT OF PUBLIC UTILITIES
Paul J. Nolan, Director

Please address reply to:
City of Tacoma
Department of Public Utilities
P. O. Box 11007
Tacoma, Washington 98411
(206) 383-2471

Attention:

July 18, 1983

Official Committee File

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
JUL 26 1983
WASHINGTON, D.C. 20510

The Honorable James A. McClure
Chairman
Senate Committee on Energy and
Natural Resources
SD-360 Dirksen Senate Office Building
Washington, D. C. 20510

Dear Senator McClure:

Enclosed are the original and four copies of Tacoma's statement on S.1132, Annual Facility Use Charge Legislation.

We are requesting that our statement be included in the hearing record on S.1132. Thank you.

Yours very truly,

Paul J. Nolan

Paul J. Nolan
Director of Utilities

Enclosure

City of Tacoma
Department of Public Utilities
Light Division

Statement on: S.1132, Annual Facilities Use Charges Legislation.

Tacoma strongly supports S.1132, amending the Federal Power Act to specify annual charges for the use of Federal dams and other structures.

The Light Division of the City of Tacoma, Department of Public Utilities (Tacoma), is a Washington municipal utility which owns and operates generation resources producing much of our system power requirements. Tacoma currently has Federal Energy Regulatory Commission preliminary permits for development of two hydroelectric projects using Federal facilities and thus is very interested in the proposed legislation.

The two projects Tacoma is currently investigating that would be subject to the proposed annual use charges are small hydroelectric facilities. These projects, as with most small hydroelectric projects, are economically marginal and their continued development is very sensitive to project costs. The assessment of an unreasonable level of annual charges would essentially preclude these projects from further development. The realistic level of charges proposed in S.1132 will not preclude development of these sites.

Tacoma supports the proposed amendment to the Federal Power Act because the method for assesing annual charges is very predictable, understandable and establishes a reasonable level of compensation without discouraging development of hydroelectric power.

Tacoma appreciates the opportunity to present comments before the Senate Committee on Energy and Natural Resources.

○